4.2 PUBLIC SAFETY: HAZARDS AND RISK ANALYSIS

4.2.1 Overview

This section addresses public safety issues associated with the proposed Project. It describes the process used to evaluate hazards and risks related to the delivery and offloading of the liquefied natural gas (LNG) by LNG carriers, storage and handling of LNG at the floating storage and regasification unit (FSRU), and pipeline transport of odorized natural gas after it has been regasified aboard the FSRU. It identifies the agencies, laws, and regulations that would regulate the safety of the proposed Project; lists the main design criteria that would be used for the proposed Project; summarizes the findings of the site-specific Independent Risk Assessment (IRA), included in this report as Appendix C1; and evaluates the potential effects of a release of LNG or natural gas to the environment.

Table 4.2-1 presents the IRA's summary of FSRU accident consequences. The IRA concluded that, given the many safety features that have been incorporated in the design of the proposed Project, accidents at the FSRU would be rare and would not reach shore, even in the case of a worst credible release such as a deliberate attack, although recreational boaters and fishermen within the defined impact area, and commercial ships within the Traffic Separation Scheme (TSS), could be affected. The IRA also recommends that additional safety analyses be conducted during final design and operations.

The FSRU would be located approximately 12.01 nautical miles (NM) (13.83 miles or 22.25 kilometers [km]) offshore. The LNG carriers and the storage and regasification aboard the FSRU would be the only parts of the Project that would involve LNG, which would be stored in non-pressurized tanks. No pipeline transport of LNG is associated with this Project. All transmission pipelines would carry only odorized natural gas.

Figure 2.1-2 in Chapter 2, "Description of the Proposed Action," identifies the areas that would be affected by the consequences of potential worst credible accidental and intentional events at the FSRU. As shown, the IRA determined that the consequences of the worst credible accident involving a vapor cloud fire would be more than 5.7 NM (6.56 miles or 10.56 km) from shore at the closest point. The effects analyzed include the risk to members of the general public of serious injury or fatality, and long-term damage to the environment. Both LNG and natural gas are highly regulated, and numerous State and Federal agencies would be responsible for reviewing the safety of the design and ensuring the safe operation of the FSRU and pipelines.

The term "risk" reflects both the probability of an incident (the frequency) and the potential adverse consequences of such an incident. Onshore pipeline accidents rarely happen but do occur. As a result, additional safeguards have been incorporated in the proposed Project to further reduce such risks. The Applicant or its designated representative would be responsible for security and monitoring measures for onshore pipelines and facilities, as well as for the FSRU and offshore pipelines. Local fire and police, and the California Highway Patrol currently provide emergency response for

Table 4.2-1 Summary of FSRU Accident Consequences

	Marine Collision[b]	Intentional[b]	Escalation[c,d]	
Breach size	1300 m^2 of area	7m^2 & 7m^2	7m^2 & 1300 m^2	7m^2 & 2x1300 m^2
Number of tanks	50% volume of 1 tank	2	2	3
Release quantity (gal / m^3) [e]	13,000,000 / 50,000	53,000,000 / 200,000	40,000,000 / 150,000	53,000,000 / 200,000
	Pool Spread Distance			
Distance down range (NM / miles / m)	0.40 / 0.45 / 730	0.35 / 0.40 / 650	0.33 / 0.38 / 610	0.43 / 0.50 / 800
	Pool Fire			
Radiative flux distance > 5 kW/m^2 (NM / miles / m)	1.60 / 1.85 / 2,970	1.42 / 1.64 / 2,640	1.35 / 1.56 / 2,510	1.74 / 2.01 / 3,230
Radiative flux distance > 12.5kW/m^2 (NM / miles / m)	0.99 / 1.14 / 1,830	0.87 / 1.01 / 1,620	0.83 / 0.96 / 1,540	1.07 / 1.24 / 1,990
Radiative flux distance > 37.5kW/m^2 (NM / miles / m)	0.49 / 0.57 / 910	0.44 / 0.50 / 810	0.42 / 0.48 / 770	0.54 / 0.62 / 1,000
	Vapor Cloud Dispersion (No Ignition)		Immediate Ignition No Vapor Cloud Hazard	
Average flammable height (feet / m)	69.9 / 21	98 / 30		
Maximum distance to LFL (NM / miles / m)	2.85 / 3.29 / 5,290	6.03 / 6.95 / 11,175		
Time for maximum distance (min)[a]	50	89		
	Vapor Cloud (Flash) Fire			
Radiative flux distance > 5 kW/m^2 (NM / miles / m)[f]	3.57 / 4.11 / 6,610	6.31 / 7.27 / 11,700		
Radiative flux distance > 12.5kW/m^2 (NM / miles / m)[f]	3.29 / 3.79 / 6,100	6.21 / 7.15 / 11,500		
Radiative flux distance > 37.5kW/m^2 (NM / miles / m)[f]	3.06 / 3.52 / 5,670	6.12 / 7.05 / 11,340		

Source: Risknology 2006, Table 3.8 (see Appendix C1).

Notes:
Pool fires and vapor cloud fires are mutually exclusive.
All radiative flux distances given from release location.
LFL = lower flammability limit; NM = nautical miles; m = meters.
Wind speed = 2 meters per second; temperature = 21 °C.
[a]Time includes liquid dispersion and evaporation.
[b]Mass balance flux rate = 0.282 kg/m^2 sec.
[c]Mass balance flux rate = 0.135 kg/m^2 sec.
[d]The escalation case was modeled as a pool fire resulting from a breach of secondary containment due to the effects of a fire. Since ignition is guaranteed, no dispersion cloud develops.
[e]Tank volume of 100,000 m^3 is used for ease of calculations; actual tank volume is 90,800 m^3.
[f] See Section 4.2.7.2 for definitions of radiative flux levels.

incidents involving existing onshore natural gas pipelines and other facilities in the area handling flammable gases or liquids; response parties would not change for the proposed onshore facilities.

The sections below present representative public comments, a discussion of other public safety reports for the proposed Project, government agency responsibilities for public safety, financial responsibilities and insurance coverage in the event of an accident, and a discussion of the public safety risk analysis process. Project background, regulations, analysis, and mitigation measures are presented by each of the three Project components: FSRU, LNG carriers, and pipelines. This section also identifies mitigation measures that would reduce the severity or likelihood of an accident, and evaluates alternatives to the proposed Project.

The proximity of components of the Project to locations where people live, work, or recreate are described in Chapter 2, "Description of the Proposed Action." The offshore environmental setting as it relates to evaluating potential hazards, i.e., wind and sea conditions, is discussed in Section 4.1.8, "Oceanography and Meteorology – Environmental Setting," and marine vessel traffic is discussed in Section 4.3, "Marine Traffic." The onshore environmental setting is described in other resource sections.

4.2.2 Representative Comments

Representative comments on public safety received during public scoping and during the public review period for the October 2004 Draft Environmental Impact Statement/Environmental Impact Report (EIS/EIR) addressed:

- The consequences of a worst-case terrorist attack from any initiating event including a shoulder- or aircraft-fired missile, or an aircraft hitting the FSRU;
- Vessel ramming or colliding with an LNG carrier or the FSRU, or explosives placed on an LNG carrier or the FSRU; identification and analysis of worst-case scenario(s); explosions and fires; and potential deaths from an LNG accident;
- Risk of hijacking of FSRU or LNG carriers and increased security concerns due to foreign vessels (and presumably foreign crews) plying the nearshore waters off the California coast;
- Marine vessel accidents; risks posed by additional ship traffic; enforcement of safety/precaution zones and notices to mariners;
- Relocation of the natural gas odorant station;
- Contributing factors to event initiation, including seismic events that could cause liquefaction or tsunamis; weather events that could produce lightning, rough seas with strong swells from various directions, and onshore winds; material defects or equipment failures; dragging an anchor over the subsea pipelines; and human error;
- Potential for errant missiles from the neighboring Point Mugu and San Clemente Range Complex;

- Adequacy of computer modeling for vapor dispersion; lack of data from large LNG spills or fires to verify the model results; and vapor cloud dispersion under varying weather conditions, including marine inversions;
- Emergency response (response time, funding, U.S. Coast Guard [USCG] role, local role) and emergency evacuation (plans, routes);
- Hazard footprint of the onshore pipelines and cumulative effect of two pipelines;
- Cumulative impact of multiple terminals;
- Training for workers;
- The proximity of the onshore natural gas pipelines to residences and schools;
- The potential for onshore pipelines and shore facilities to be terrorist targets;
- The "untested design" of the FSRU; and
- The safety record of ventures owned or operated by the Applicant outside of the U.S.

The potential for seismic events, including tsunamis, is discussed in Section 4.11, "Geologic Resources," and navigation safety is addressed in Section 4.3, "Marine Traffic." In response to public concerns, the odorant used to aid in leak detection would be added to the natural gas on the FSRU before it would be sent to shore; the odorant is discussed in Section 4.12, "Hazardous Materials." The proximity of the onshore pipelines to residences and schools is discussed in Section 4.13, "Land Use." Emergency response capabilities are described in Section 4.16, "Socioeconomics." The potential for oil spills and contingency plans that would be in place to respond if they were to occur are discussed in Section 4.18, "Water Quality."

Accidental hazards for an offshore terminal include natural phenomena, collisions with other ships, spills during LNG transfers, and accidents associated with the storage and regasification of LNG. These events could result in consequences that include the puncture of an LNG cargo tank from a ship collision and a subsequent fire or combustion-related explosion caused by an LNG leak or spill on board the FSRU. Intentional threats can range from an insider threat to intentional external attacks using weapons or delivery modes such as airplanes, ships, or boats. Table 4.2-2 lists representative hazards and threats identified above and briefly indicates how they were evaluated in the public safety analysis.

Table 4.2-2 Representative Hazards and Threats Considered in the Public Safety Analysis

Hazards and Threats	Evaluation/Resolution
Natural Phenomenon	
Lightning	All-metal ships are rarely damaged, and injuries or deaths are uncommon. Ships are frequently struck, but the high conductivity of the large quantities of metal, with hundreds of square yards of hull in direct contact with the water, causes rapid dissipation of the electrical charge. The FSRU and LNG carriers would be designed to meet lightning protection standards, National Fire Protection Association, Lightning Protection Code 780.
Rough seas/strong swells that damage the FSRU or cause it to lose one or more mooring lines	The FSRU and its mooring system would be designed to withstand at least the combined wind, wave, and current forces of the most severe storm that could occur within any 100-year period. Thrusters on the FSRU would assist it to maintain its position in the short term. The tugboat that would be permanently stationed near the FSRU could also maintain the FSRU's position in the event of damage to one or more mooring lines.
Tsunami damage to FSRU or pipelines	The FSRU, risers, moorings, and subsea pipelines must be designed to withstand tsunamis. A tsunami would not damage the moored FSRU and LNG carriers because the size of the wave/surge would be quite small—a few inches at the most—due to the deep water (2,900 feet or 884 m). Although it is possible that the current associated with a tsunami wave would affect the gas risers, a maximum current value would be used for the final design of the risers to avoid other damage.
Seismic-induced damage to pipelines	The offshore gas pipelines could be adversely affected by seismic activity but would be designed to accommodate anticipated maximum lateral/vertical motion from earthquakes (permanent deformation of seafloor) during the final design stage. If seafloor motion were to exceed allowable stresses in the pipelines, pipelines could rupture and cause a leak. The loss of pressure would induce the safe shut-down of the system, and natural gas would rise to the surface. Few ignition sources exist in the vicinity of the proposed offshore pipelines, and closer to shore the pipeline would be deeply buried by HDB. Onshore pipelines would be similarly designed to accommodate anticipated displacement by earthquakes and a loss in pressure would activate their shut-down system.
Process Safety Accidents	
Material defects and equipment failures	Procured equipment, fabrication, construction, and installation would be verified by qualified third parties. The FSRU and LNG carriers would be independently inspected by a ship classification society during their construction and periodically thereafter. BHPB would obtain a safety management certificate for the FSRU.
Ballast system malfunction	Considered in the hazard identification workshop. Potential for sudden listing possibly causing mooring line failure or disconnection of loading arm. Consequences addressed by accidental explosion between vessels scenario.
Fire/explosion on FSRU or LNG carrier	Leak detection and extensive fire suppression equipment would be located on both the FSRU and LNG carriers. If a fire were to result in loss of containment, the consequences would be addressed by either the marine collision (single tank) pool fire or escalation scenarios.

Ignition source in vaporizers	Considered in the hazard identification workshop. Recommendation to verify safeguards associated with the flame during review of final FSRU design.
Accidental explosion between vessels due to a release of LNG during transfer from the LNG carrier to the FSRU; loading arm failure	Considered in the hazard identification workshop and further investigated with a special study. Evaluated a condition in which the two side-by-side vessels would confine a mixture of LNG that could reach concentrations within the flammable range. The results indicated an almost negligible effect on the FSRU with the separation between the two vessels increasing by about 4 feet (1.2 m).
Release of LNG to non-cargo containing areas, e.g. ballast tanks, void tanks	Considered in the hazard identification workshop. Consequences addressed by marine collision (one-tank) or escalation (two-or three- tank) scenarios.
Accidental/Intentional Collisions	
Small aircraft or helicopter hitting FSRU	An accidental collision would be very unlikely. The consequences of an intentional event would be the breach of one storage tank on the FSRU or LNG carrier with loss of containment and fire. Evaluated by the pool fire considered in the marine collision (one-tank) scenario.
Small vessel ramming/colliding with FSRU	The Moss tank design demonstrates robust performance against marine collisions. Only vessels with very specific geometry, strength, and speed have the physical capacity to penetrate the FSRU hull's structural steel and breach the cargo containment. Small vessel unlikely to have enough mass to penetrate inner hull of double-hulled FSRU or LNG carriers; damage would be primarily to the small vessel. Evaluated in collision analysis for the IRA (Appendix D of the IRA, included as Appendix C1 of this document).
Large ship colliding with FSRU	The Moss tank design demonstrates robust performance against marine collisions. Only vessels with very specific geometry, strength, and speed have the physical capacity to penetrate the FSRU hull's structural steel and breach the cargo containment. Addressed by the marine collision scenario in the IRA.
Large passenger ship colliding with FSRU or LNG carrier	The deliberate takeover of a large passenger ship to strike the FSRU was considered in the security workshop and marine collision analysis. This event is highly unlikely and was not considered further. The incidence of collisions involving cruise ships is even lower than other vessels, and the marine collision analysis demonstrates that few cruise ships transit the area. Most cruise ships offshore California travel south from the Port of Los Angeles/Long Beach or from San Diego. Cruise ships in the vicinity of the FSRU use the TSS. Cruise ships are highly regulated with extensive collision avoidance and communication capabilities. Cruise ships must implement USCG-approved security plans and have security officers.
Commercial airliner striking FSRU	This event would be highly unlikely. The use of a commercial airliner to deliberately strike the FSRU was considered in the security workshop, which concluded that this event is highly improbable due to recent changes in the security of the airline industry; however, if it were to occur, the consequences would be similar to the two- or three-tank escalation event.
Intentional Event	
Hijacking of FSRU	The hijacking of the FSRU would be highly unlikely. BHPB would implement a USCG-approved security plan, have redundant communication systems, and patrol the safety zone/Area to be Avoided (ATBA) to identify intruders and take appropriate action. The FSRU is not

	powered, other than thrusters, and would be very difficult to remove from its mooring, and due to its remote location, the FSRU is considered to be a less attractive target than other “softer” targets.
Hijacking of LNG carrier, transit to shore, and deliberate release of LNG or natural gas	The LNG carriers would implement USCG-required security plans (see Appendix C3), which would thwart such events. The LNG carriers would be either near the FSRU, which is at a remote location, or farther offshore; therefore, other hazardous vessels are considered more likely targets. Evaluated in the security workshop, but not considered credible due to recent changes in security in the marine industry.
Takeover of LNG carrier and intentional collision with FSRU.	Evaluated in the security workshop. LNG carriers would be in frequent communication with Cabrillo Port during the entire voyage using established, secure communication protocols and would be subject to the USCG security requirement (see Appendix C3); therefore, early detection of an attempted takeover is very likely. This would probably not result in the total loss of the LNG cargo as the release would probably be only from the affected tanks. The consequences are addressed in the marine collision (one-tank) and escalation (two-or three-tank) scenarios.
Shoulder or aircraft-fired missile or other tactical weapons	The double hulls of the FSRU and LNG carriers would be robust. Penetration of one tank could result in consequences similar to the marine collision (one-tank) release scenario. The two-tank, 7 square-meter (m^2) scenario is based on one missile and then a second missile successfully penetrating LNG tanks on the FSRU or LNG carrier. Sandia recommended this scenario based on emerging guidance from the U.S. Department of Homeland Security (DHS) and from the intelligence community as noted in the Sandia report and the associated classified report on possible intentional threats (“Threat and Breach Analysis of an LNG Ship Spill Over Water” Sandia National Laboratories, May 2005 [SECRET]). Worst credible case is addressed in the intentional (two-tank) and/or escalation (three-tank) scenario.
Bomb delivery by small craft	A successful attack could result in potential loss of containment on both the LNG carrier and FSRU with possible ignition and major fire. The potential consequences are evaluated in the escalation (two or three-tank) scenario. The ATBA and the safety zone would be patrolled and would deter intruders in accordance with the security plan. Successful delivery in this manner would be unlikely.
Assault on FSRU by diver(s)	The distance of the FSRU and LNG carriers offshore make this event unlikely. Patrol vessels would warn vessels in the ATBA and deter vessels from the safety zone. However, if successful, the consequences would be similar to those of the marine collision (one-tank) release scenario or in the worst credible case, the escalation (two or three-tank) scenario.
Deliberate release of unignited LNG offshore.	Considered in the hazard identification workshop. Correlated to intentional event (two-tank) vapor cloud dispersion and flash fire.
Other Events	
Errant missiles from US Navy complex could strike the FSRU or an LNG carrier	BHPB would coordinate activities with the U.S. Navy to avoid conflicts with Navy activities. Errant missiles rarely if ever occur, and an errant missile striking the FSRU or an LNG carrier is highly improbable. The escalation (two or three-tank) scenario would address the consequences.
Dragging an anchor over a subsea pipeline	The pipelines could be damaged resulting in a leak of natural gas. The loss of pressure would be monitored at the FSRU and would induce the safe shut-down of the system, and natural gas would rise to the surface. Few ignition sources exist in the vicinity of the proposed offshore pipelines. The natural gas would also be odorized at the FSRU.

4.2.3 Independent Risk Assessment and Sandia National Laboratories Review

The LNG industry has been operating for 40 years. In those 40 years, fewer than 20 marine accidents involving LNG have occurred worldwide, none of which resulted in a significant release of LNG (see Chronological List of LNG Accidents in Appendix C3).

Previous studies of LNG accident history were researched for this document. A 1977 report prepared by Socio-Economic Systems (1977) for a proposed onshore LNG terminal near Oxnard reviewed results from several different models and concluded that "[t]he current state of the art does not permit judging which approach and which results are right, and which are wrong. Thus, at the present time, neither the SAI model nor the other cloud models can provide definitive conclusions." Table VII from that report shows that for a release of 26.4 million gallons (100,000 m^3) of LNG, downwind impact distances were estimated to be 1.27 miles (2 km), 3.72 miles (6 km), 26.2 miles (42 km), 76.0 miles (122 km), or 127 miles (204 km), depending on the model used. Modeling capabilities have improved since the 1977 study and continue to evolve as new information becomes available.

To better determine the potential effects of a large spill of LNG to water, the lead agencies commissioned a team of experts to prepare a site-specific evaluation of the design concept and plans for the Deepwater Port (DWP), taking into consideration local environmental conditions and the concerns expressed by the public. The IRA that was prepared in 2004 as an analysis for the DWP did not attempt to recreate consequence modeling conducted for the 1977 study cited above, but instead presented new methodology and analysis specific to the proposed Project.

In December 2004, after publication of the October 2004 Draft EIS/EIR, Sandia National Laboratories (Sandia) issued a report entitled "Guidance on Risk Analysis and Safety Implications of a Large Liquefied Natural Gas (LNG) Spill Over Water" (Sandia 2004). The guidance report lays out a recommended framework for analyses of large LNG spills onto water.

The USCG commissioned the authors of the Sandia guidance report to conduct a third-party technical review of the 2004 IRA. Sandia reviewed the methodology used in the 2004 IRA and made recommendations for revised modeling and analysis of the potential impact area in its 2006 report (Appendix C2 of this document). The conclusions are summarized in the following excerpt:

> This report summarizes the results of the Sandia review of the Cabrillo Port IRA and supporting analyses. Based on our initial review, additional threat and hazard analyses, consequence modeling, and process safety considerations were suggested. The additional analyses recommended were conducted by the Cabrillo Port IRA authors in cooperation with Sandia and a technical review panel composed of representatives from the Coast Guard and the California State Lands Commission. The results from the additional analyses improved the understanding and confidence

in the potential hazards and consequences to people and property from the proposed Cabrillo Port LNG Deepwater Port Project (Sandia 2006).

The 2006 IRA (Appendix C1 of this document) incorporates Sandia's recommendations, and the conclusions and recommendations of the 2006 IRA are the result of collaboration and concurrence between Sandia and the IRA authors. The public safety analysis of the FSRU in Section 4.2 is based on the 2006 IRA and on the Sandia guidance.

The IRA evaluated the potential consequences of an accident and fire based on the total volume of LNG that would be stored on the FSRU or in an LNG carrier while berthed at the FSRU during unloading. The amount of LNG that would be released would never exceed the total storage capacity of the FSRU because prior to the arrival of LNG carriers delivering LNG to the FSRU, the FSRU would regasify enough LNG and send it to shore via the offshore pipelines to make room for the new delivery. The LNG carriers would use routes that are farther from shore than the FSRU and therefore farther away than the FSRU from most recreational boating and fishing areas and the vessel traffic lanes. As such, LNG carriers would not present risks or hazards to the general onshore public while in transit to the FSRU. Since the objective of the IRA was to evaluate risks to the public, it did not consider the potential effects of an accident at an LNG carrier during transit to the FSRU.

Although the Sandia guidance includes a specific evaluation of potential impacts associated with incidents involving LNG carriers, the USCG determined that the site-specific modeling and analysis of the FSRU would be more appropriate for the LNG carrier analysis in this document. Potential public safety impacts associated with natural gas transportation by pipeline have been extensively evaluated in the past, based on decades of operational history for hundreds of thousands of miles of transmission pipelines. For example, the likelihood of an accident can be extrapolated from the extensive historical records; therefore, the IRA did not include analysis of onshore and offshore pipelines.

4.2.4 Government Responsibilities for Public Safety

4.2.4.1 Federal and State Agency Jurisdiction and Cooperation

The design, construction, and operation of natural gas facilities is highly regulated by a number of Federal and State agencies as indicated throughout this document. Federal, State, and local agencies also would participate in emergency planning and response to releases. Agency jurisdiction and responsibilities for the proposed Project are summarized in Table 4.2-3. The USCG is responsible for reviewing the design and safety of the DWP for both the FSRU and LNG carriers and would consult with the California State Lands Commission (CSLC). For offshore pipelines, the agencies with authority over pipeline design and safety include the U.S. Department of Transportation (USDOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) Office of Pipeline Safety (OPS), the California Coastal Commission (CCC), and the CSLC.

PHMSA OPS and the California Public Utilities Commission (CPUC) Division of Safety and Reliability have jurisdiction over onshore pipelines.

Table 4.2-3 Lead and Cooperating Agency Authority for the Project

Facility and Purpose	General Location	Primary Implementing Agency(ies)			
		Siting	Design & Safety Regulation	Safety Inspections	Enforcement Actions
FSRU	Offshore: Outer Continental Shelf, Federal waters	**USCG, MARAD** *CSLC, MMS, PHMSA OPS, CCC*	**USCG** *CSLC, CCC*	**USCG**	**USCG**
Offshore pipelines Two parallel subsea pipelines *Transfer natural gas from FSRU to shore crossing.*	Offshore: Outer Continental Shelf, Federal waters	**USCG, MARAD,** *CSLC, MMS, PHMSA OPS, CCC*	**PHMSA OPS,** *CSLC,* *CCC*	**PHMSA OPS,** *CSLC,* *MMS,* CCC	**PHMSA OPS,** *CSLC,* *MMS,* *CCC*
Offshore pipelines Two parallel subsea pipelines *Transfer natural gas from FSRU to shore crossing.*	Offshore: State waters within 3 NM (3.5 miles or 5.6 km) of shore	**USCG, MARAD** **CSLC, CCC** *MMS, PHMSA OPS*	**PHMSA OPS, CSLC** *CCC*	**PHMSA OPS, CSLC** *CCC*	**PHMSA OPS,** *CSLC,* *CCC*
Shore crossing at Ormond Beach *Connect the two subsea parallel pipelines to existing onshore infrastructure.*	Ormond Beach, Ventura County	**USCG, MARAD** **CSLC, CCC,** **PHMSA OPS**	**PHMSA OPS, CSLC** *CCC*	**PHMSA OPS, CSLC** *CCC*	**PHMSA OPS,** *CSLC*, *CCC*
Metering station at Ormond Beach *Measure and transfer ownership of natural gas.*	Reliant Energy Ormond Beach Generating Station, Ventura County	**CPUC SRB, CSLC, CCC** *PHMSA OPS*	**CPUC SRB,** **PHMSA OPS, CSLC**	**CPUC SRB,** **PHMSA OPS**	**PHMSA OPS,** *CPUC SRB*
Onshore pipelines and facilities *Transport gas to distribution system.*	Ventura County, Los Angeles County, and City of Oxnard	**CPUC SRB** *PHMSA OPS, CSLC*	**CPUC SRB,** **PHMSA OPS**	**CPUC SRB,** **PHMSA OPS**	**CPUC SRB, PHMSA OPS**

Notes:

Agencies shown in **boldface** have primary authority (either statutory or through delegation of Federal powers to a State agency through a memorandum of agreement or regulatory mandate). Agencies shown in *italics* are key cooperating agencies.

CCC = California Coastal Commission; CPUC SRB = California Public Utilities Commission, Consumer Protection and Safety Division, Safety and Reliability Branch; MARAD = U.S. Maritime Administration; MMS = Minerals Management Service; PHMSA = U.S. Department of Transportation (USDOT) Pipeline and Hazardous Materials Safety Administration; OPS = Office of Pipeline Safety; USCG = U.S. Coast Guard.

Safety standards that apply to the Project include specific requirements for Federal and State agency inspections and oversight of all phases of the Project. Based on experience with the operator, these agencies may choose to increase the frequency and level of detail for facility compliance inspections to ensure that safety requirements are met. For Federal agency records, the public may request copies of inspections through a Freedom of Information Act (FOIA) request (Reference 5 U.S.C. 552). Reviews and inspections by California agencies are subject to the California Public Records Act (California Government Code, § 6250, et seq.).

The LNG Interagency Permitting Working Group was established to facilitate interagency communication and cooperation among State and local agencies that may be involved in permitting an LNG facility in California. Participating agencies with responsibilities in the areas where the proposed Project is located include the California Air Resources Board (CARB), the CCC, the California Energy Commission (CEC), the CPUC, the CSLC, the Department of Conservation, the California Department of Fish and Game (CDFG), CDFG's Office of Oil Spill Prevention and Response (OSPR), the Electricity Oversight Board, the Office of Planning and Research, the Bay Conservation and Development Commission, the Department of General Services, the Governor's Office of Emergency Services, the Port of Humboldt Bay, the Port of Long Beach, the Ventura County Planning Department, and the USCG.

4.2.4.2 Standardized Emergency Management System (SEMS)

SEMS (California Government Code § 8607(a)) provides a unified response for all elements of California's emergency management program, including managing response to multi-agency and multi-jurisdictional emergencies. SEMS consists of five organizational levels that are activated as needed: field response, local government, operational area, region, and State. This management scheme incorporates the use of the Incident Command System, master mutual aid agreements, existing discipline-specific mutual aid, the operational area concept, and multi-agency or inter-agency coordination.

The USCG responds to emergencies offshore. Should an incident involving the FSRU occur, the relatively large distance from shore would be expected to allow sufficient time for notification and mobilization of emergency response resources, e.g., additional tug support, fireboats, and rescue for facility or carrier personnel.

In addition, deepwater ports are required to develop and maintain an emergency manual that meets the requirements of 33 Code of Federal Regulations (CFR), Part 127, Subpart B, "Waterfront Facilities Handling Liquefied Natural Gas," which requires initial training with refresher training at least once every five years. Regulations contained in 33 CFR Part 150 impose annual self-inspection requirements wherein operators are required to check and ensure compliance with operations and emergency manuals.

4.2.5 Financial Responsibilities in the Event of an Accident

4.2.5.1 Personal Injury Liability

The DWP would be owned and operated by the Applicant. In the event of claims filed due to an accident at the DWP, 33 United States Code (U.S.C.) § 1518(a)(1)-(2) and (b) of the Deepwater Port Act (DWPA), states that the following regulations would be "administered and enforced by the appropriate officers and courts of the United States":

- If the injured person is an employee working on a deepwater port, such persons are covered by Division 4 of the California Labor Code, commencing with § 3200, relating to workers' compensation;
- If the injured person is a Federal employee injured during the course of employment, such persons are covered by the Federal Employees' Compensation Act (5 U.S.C. Chapter 81, § 8101);
- If the injured person qualifies as a seaman, the remedy is through the Jones Act (Admiralty action - 46 App. U.S.C. Chapter 18, § 688); and
- If the injured person is someone other than an employee or a seaman, the remedy is through California tort law.

Liability for damages related to the onshore pipeline, as with any onshore gas pipeline accident, would also be governed by the laws of the State of California relating to tort liability. As with any gas pipeline accident, to the extent that damages were the result of negligence on the part of the Southern California Gas Company (SoCalGas), the liability may be treated by the CPUC as a cost of doing business. The costs necessary for covering that liability would then be covered by the utility's gas rates, and the availability of funds necessary to cover any such damages would therefore be assured. Costs necessary to cover punitive damages or liabilities that arise from gross negligence or willful misconduct, though, may not necessarily be passed on to ratepayers. Funds necessary to cover such costs in that event would come from the utility's own assets.

The topic of how the Project would affect private party insurance rates is outside the scope of this Revised Draft EIR.

4.2.5.2 Environmental Harm

Under Federal law, the Oil Pollution Act (OPA) of 1990 (33 U.S.C. Chapter 40) would apply, but only for purposes of an oil spill. LNG is not "oil" within the context of OPA 90. OPA 90 might apply to the response to a ship accident to the extent that the response costs and damages are caused by the discharge of oil from the ship's fuel tanks, bilges, etc., or if the spill comes from fuel tanks located at the DWP or other Project-related vessels such as the back up fuel on supply boats. OPA 90 would apply to the LNG carriers and the FSRU because of the quantity of fuel that would be stored on each. As the vessel operator, BHPB would be required to maintain USCG-approved fleet shipboard oil emergency plan/vessel contingency plan for all Project vessels.

The Lempert-Keene-Seastrand Oil Spill Prevention and Response Act of 1990 (Chapter 1246, California Statutes of 1990) is a State law, the liability and financial responsibility provision of which within the California Government Code applies only to oil spills. Provisions of the Act within the California Public Resources Code that address design, construction, operations, and maintenance apply to LNG. The California Harbor & Navigation Code imposes strict liability for damages arising out of discharge of natural gas or other specified activities (California Harbors and Navigation Code § 294). This would cover nearly any accident that occurs offshore that causes damages incurred by any injured party which arise out of, or are caused by, the discharge or leaking of natural gas into or onto marine waters, or by any exploration in or upon marine waters, from any offshore facility at which there is exploration for, or extraction, recovery, processing, or storage of, natural gas, or any vessel offshore in which natural gas is transported, processed, or stored, or any pipeline located offshore in which natural gas is transported.

In accordance with 33 U.S.C. § 1518(b), general California tort law would also apply under the DWPA.

4.2.5.3 Applicant's Insurance Coverage

For the parts of the Project that would be constructed, owned, and operated by the Applicant, the Applicant would carry casualty insurance to cover costs associated with unusual expenditures for emergency response. The Applicant is a Delaware corporation qualified to do business in the State of California. The corporation carries $250 million per occurrence in pollution liability insurance, $500 million per occurrence in protection and indemnity insurance (for crew injury and vessel liability and pollution), and $750 million per occurrence in excess liability insurance. All of these policies are currently in place for the corporation and would be applicable to the Project during construction and operations.

It is the U.S. Maritime Administration's (MARAD's) position that, as a matter of policy, the Secretary, in implementing the provisions of the DWPA, does not require any additional coverage for third-party claims other than that currently mandated by Federal or State law. However, the adjacent coastal state may require additional conditions that may address this issue, in accordance with 33 U.S.C. § 1508(b)(1): "If the Governor notifies the Secretary that an application, which would otherwise be approved pursuant to this paragraph, is inconsistent with State programs relating to environmental protection, land and water use, and coastal zone management, the Secretary shall condition the license granted so as to make it consistent with such State programs."

4.2.5.4 Local Emergency Services Funding and Cost Recovery for Incidents

Corporate taxes, franchise fees, and other taxes that would be paid by the Applicant or its designated representative would contribute to the city and county funding for emergency services provided for onshore pipeline incidents. Local governments also have the legal authority to conduct cost recovery actions for large-scale incidents requiring unusual expenditures of resources. For disasters, each of the local response agencies also has the option to request State funding, based on having adopted SEMS practices for multi-agency and multi-jurisdictional responses.

4.2.6 Public Safety Risk Analysis Process

Figure 4.2-1 illustrates the process used to evaluate risks of the proposed Project:

- Identify and evaluate potential hazards;
- Define scenarios to bracket the range of potential accidents (resulting either from operations or intentional attacks);
- Use state of the art computer models to define the consequences for each scenario (including the worst credible case scenario);
- Compare the results to existing safety thresholds and other criteria; and
- Make the results available to decision makers and the public, while also ensuring that release of relevant information does not in turn create a security threat.

Certain risks were eliminated from consideration through this process because the potential to impact the public did not exist. For example, the LNG carriers would not come any closer to the shore than the FSRU and, therefore, would not present risks or hazards to the public while in transit. Also, jet fires (see Section 4.2.7.2) could only occur at the point of origin of the LNG release, i.e., the FSRU or LNG carrier; therefore, because the public would be excluded from the area surrounding these vessels, they could not be affected.

The environmental and occupational safety record for the Applicant's worldwide operations, including, for example, mining ventures overseas was not considered in evaluating potential public safety concerns associated with this Project because such operations are not directly comparable to the processes in the proposed Project. Injuries to crew members are not included in the scope of analyses under the National Environmental Policy Act (NEPA) or the California Environmental Quality Act (CEQA).

Levels of risk that are "significant" to members of the public can be difficult to define and often vary widely, depending upon public perception and how close a proposed Project would be to the places where an individual lives, works, and recreates. Definitions for significant adverse effects on public safety—consequences deemed to represent a significant impact—were developed based on scoping comments, analyses from previous environmental assessments conducted in California, and through consultation with the lead agencies.

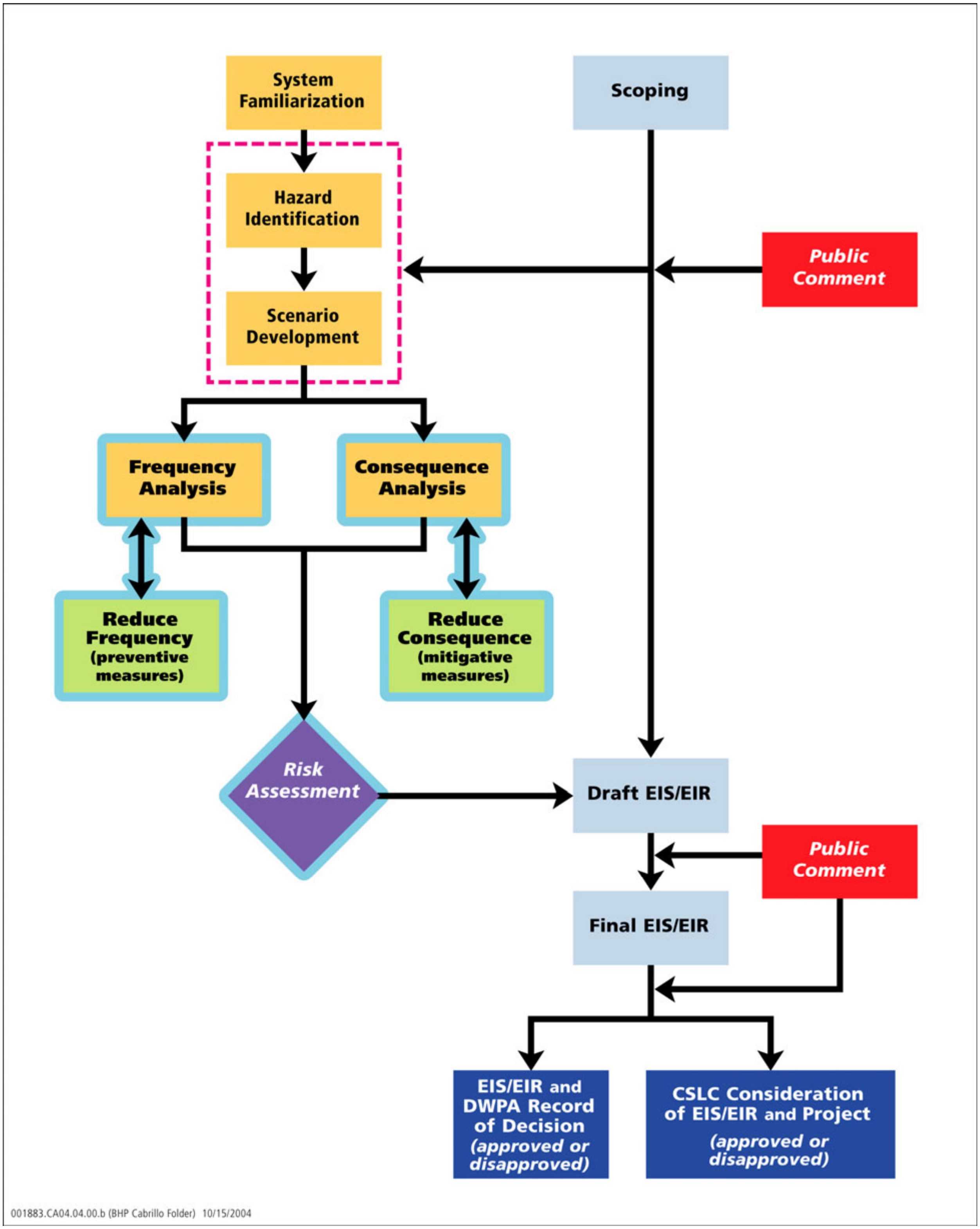

Figure 4.2-1 The Risk Assessment Process

4.2.6.1 Frequency Analysis

Frequency analysis estimates the likelihood of occurrence for each of the event sequences that were identified in the hazard identification steps. Likelihood can be expressed in frequency and probability. Frequency is the expected number of occurrences of the event per unit time. Probability is the measure of how likely it is that the event will occur.

Frequency data can be obtained from historical data, event-tree analysis, theoretical modeling, judgment evaluation, and other techniques. For potential incidents involving LNG releases at the FSRU, event-tree analysis was used because of the very high consequence, low likelihood events of interest for releases. The IRA includes estimated frequencies for the scenarios that were considered.

The potential frequency of collisions with Project vessels or the FSRU and members of the public in recreational craft, fishing, or other commercial or military vessels was based on analyses of local marine traffic and is discussed in Section 4.3, "Marine Traffic." The potential frequency of incidents involving onshore and offshore pipelines was estimated at approximately four serious injuries per 100,000 pipeline miles per year and about one fatality per 100,000 pipeline miles per year based on historical data compiled by PHMSA OPS. The data also provide enough information to develop an estimate of the potential frequency per pipeline mile of a serious injury requiring hospitalization or a fatality. The potential risk associated with these incidents cannot be reliably estimated due to the uncertainties in the number of people that might be in the area at the time of an incident and the nature and extent of any injuries.

Risk assessments of LNG and natural gas facilities evaluate the frequencies of events that lead to a particular outcome based on the design, operational history, and historical incident data. Frequencies were not estimated for intentional acts of arson or sabotage, but the consequences of such potential acts are considered to be bracketed within the worst credible case scenarios, i.e., they would be no worse than the scenarios analyzed in the IRA.

Potential terrorist targets include any location or facility where people gather and loss of life in an attack would be high, where damage would cause significant disruption in providing essential services, or that has special significance. A representative range of such possibilities was considered by the experts who participated in the security and vulnerability workshop. A successful attack on the FSRU, an LNG carrier, or the subsea or onshore natural gas pipelines would cause a temporary disruption in the delivery of natural gas in Southern California, but would not be expected to cause serious injury or death to large numbers of the public and far fewer than from a successful attack on an unprotected (soft target) facility where people regularly gather, e.g., the stands at the local football or soccer stadium. For this reason, the participants in the workshop did not consider it to be as attractive a target as many other targets that are more easily accessible.

The frequency or probability of arson, intentional sabotage, or an intentional attack cannot be reliably estimated. However, consequences of an intentional attack on an LNG carrier or the FSRU and its associated pipelines are expected to be bracketed by the analyses of worst credible case scenarios, which were defined and evaluated without regard to the likelihood of any sequence of events that would lead to this event actually occurring. Thus, they would be no worse than the scenarios analyzed in the IRA. The planning for the above-mentioned events and specific intervention actions is subject to national security confidentiality and is not addressed in this document.

4.2.6.2 Comparison of Project Risks with Other Transportation Risks

Conservative estimates of the frequencies of incidents with significant public safety impacts involving marine collisions or the worst credible case releases of LNG from the FSRU are presented in the IRA and range from rare to extremely low likelihood. To provide a context for evaluation, Table 4.2-4 shows risks associated with other various types of transportation incidents.

Table 4.2-4 Comparison of Transportation Risks

Type	5-Year Average	General Population Risk Per Year	Risk Based on Exposure or Other Measures
Motor vehicle	41,616	1 in 6,300	1.7 deaths per 100 million vehicle miles.
Large trucks[a]	5,195	1 in 51,000	2.8 deaths per 100 million vehicle miles.
Motorcycles	2,222	1 in 119,000	22 deaths per 100 million vehicle miles.
Railway	1,096	1 in 242,000	1.6 deaths per million train miles.
Bicycles	795	1 in 333,000	---
Commercial air carriers[b]	169	1 in 1,568,000	0.7 deaths per 100 million aircraft miles; 0.19 deaths per million aircraft departures.

Source:

A Comparison of Risk, U.S. Department of Transportation, http://hazmat.dot.gov/riskcompare.htm

Notes:

[a]Defined as having a gross vehicle weight greater than 10,000 pounds.

[b]Includes large and commuter airlines.

4.2.7 FSRU and LNG Carriers

The proposed Project involves the transport and storage of LNG, which would be transferred from LNG carriers into the three spherical Moss storage tanks on the FSRU. The LNG would be converted into pipeline-quality natural gas and odorized on the FSRU prior to transport to shore via the two subsea pipelines. Odorization would ensure that any leaks of gas from the pipelines would be readily detectable by people with a normal sense of smell. Once onshore, the odorant concentration in the gas would be monitored, and additional odorant would be added, if necessary, before it flows into the onshore gas transmission pipeline system, owned and operated by SoCalGas. The hazards associated with LNG and natural gas are described below.

4.2.7.1 LNG Properties and Hazards

When natural gas is cooled to a temperature of -260 degrees Fahrenheit (°F) (-162 degrees Celsius [°C]), it converts from a gas to a clear, colorless, and odorless liquid, which reduces the volume by a factor of 600 and makes it possible to efficiently store and transport large quantities of this fuel in specially designed spherical tanks and tanker ships. LNG is not stored under pressure; the storage tanks operate at essentially atmospheric pressure, but are heavily insulated to keep the LNG cold. The three main hazards that LNG presents are flammability, dispersion, and cryogenic temperatures (NASFM 2005).

Flammability

LNG is composed primarily of 85 to 96 percent methane with other light hydrocarbon components, such as propane, ethane, and butane. LNG is flammable in its vapor state at a concentration range of 15 percent (15 percent methane, 85 percent air) to 5 percent (5 percent methane, 95 percent air), and the ignition temperature at its flammable concentration range is approximately 1,004 °F (540 °C).

Dispersion Hazards

Methane is a flammable and odorless gas, and although it is not toxic, it can act as an asphyxiant when it displaces oxygen in a confined space. LNG is typically stored at low pressure, i.e., less than 5 pounds per square inch gauge (psig) (3,500 kilograms per square meter [kg/m^2]), in well-insulated containers. Heat will cause the liquid to boil, and removal of the boil-off gas helps to keep the LNG in its liquid state – a phenomenon known as “auto-refrigeration.” The density of LNG is 3.9 pounds (1.8 kg) per gallon (0.004 cubic meter [m^3]), which is about half that of water.

If LNG is spilled on the ground, it will boil rapidly at first, then more slowly as the ground cools. If it is spilled on water, it will float and vaporize very rapidly because the water temperature is significantly warmer than the LNG. The resulting vapor cloud is very cold and dense, and quite visible because it condenses water out of the air. If there is no ignition source, the vapor cloud hugs the ground and spreads laterally. As the cloud becomes warmer than -256 °F (-160 °C) and mixes with air, the expanding vapor cloud may not be visible. As the vapor continues to disperse, the cloud will eventually become neutrally buoyant. A cloud of natural gas may ignite; however, it has not been shown to explode if it is not confined. LNG itself will not burn or explode; it must be warmed to its gaseous state and mixed with air in the proper concentration to allow combustion to occur.

Cryogenic Hazards

Contact with a cryogenic material can cause severe damage to the skin and eyes. It can also make ordinary metals become brittle, which would allow them to fracture. Therefore, cryogenic operations require specialized containers and piping. LNG is typically stored in metal containers consisting of 9 percent nickel steel or aluminum, and is transported through stainless steel pipes that are capable of handling materials with very low temperatures. Insulation is used on the storage tanks and piping to protect workers from potential contact freeze burns.

4.2.7.2 LNG Risk-Related Scenarios

Planners and responders prepare for emergencies by considering the probable risk that something may go wrong and, if it does, what the appropriate response and outcome should be. With regard to LNG, there are four general risk-related scenarios: (1) fire, (2) vapor cloud explosion (a vapor cloud of natural gas if confined can explode), (3) cryogenic effects, and (4) rapid phase transition (NASFM 2005).

Fire

LNG quickly returns to its vapor phase (natural gas) as it absorbs heat from the surface on which it is spilled. Initially, this vapor is heavier than air and will form a cloud just above the surface; as the vapor warms further, it becomes more buoyant, at which time it rises and disperses. When the concentration of natural gas vapor in air is between 5 and 15 percent and an ignition source is present, it will burn. LNG presents three potential fire risk scenarios: pool fire, jet fire, and vapor cloud fire.

- **Pool Fire.** Spilled LNG may form a liquid pool from which natural gas forms via evaporation. As the vapor disperses and reaches its flammability range, if an ignition source is encountered, the vapors will ignite and travel back to the origin resulting in a pool fire. If the pool forms within a confined area, the fire will remain contained and will continue to burn until the fuel is consumed. If the spill occurs outside a confined area, e.g., on the ground or on water, the burning pool is free to flow based on topography or wind and currents.
- **Jet Fire.** If LNG in the storage tanks is released, the material discharging through the hole will form a gas jet. If this material finds an ignition source while in its flammable range, a jet fire may occur. This type of fire is unlikely for an LNG storage tank because the material is not stored under pressure. However, jet fires could occur in pressurized vaporizers or during LNG offloading or transfer operations when pressures are increased by pumping. A fire occurring under this scenario could cause severe damage, but would be confined to a local area and would be limited by onboard safety systems; therefore, because this type of fire would not affect the general public, jet fires are not discussed further.
- **Vapor Cloud (Flash) Fire.** When LNG is released to the atmosphere, a vapor cloud forms and disperses by mixing with the air. If the vapor cloud ignites before it is diluted below its lower flammable limit, a flash fire could occur. Ignition can occur only within that portion of the vapor cloud having a concentration within the above-defined flammable range. The entire cloud would not ignite at once. However, a flash fire may burn back to the release point resulting in either a pool fire or a jet fire, but will not generate damaging overpressures as long as it is unconfined.

Table 4.2-5 shows a range of values for thermal radiation that can be expected to cause damage or injury to exposed people or property. By way of comparison, the solar constant is 1.35 kW/m^2.

Table 4.2-5 Common, Approximate Thermal Radiation Damage Levels

Incident Heat Flux (kW/m^2)[a]	Type of Damage
35 – 37.5	Damage to process equipment including steel tanks, chemical process equipment, or machinery
25	Minimum energy to ignite wood at indefinitely long exposure without a flame
18 – 20	Exposed plastic cable insulation degrades
12.5 – 15	Minimum energy to ignite wood with a flame; melts plastic tubing
5	Permissible level for emergency operations lasting several minutes with appropriate clothing

Source: Sandia 2004.
Note:
[a]Based on an average 10 minute exposure time.

Sandia has stated that 5 kW/m^2 is commonly considered the heat flux level appropriate for protection of human health and safety (Sandia 2004). This is based on both exposure time and damage levels. The National Fire Protection Association standard for the production, storage, and handling of LNG (Standard 59A) recommends that an incident heat flux value of 5 kW/m^2 be the design level that should not be exceeded at a property line or where people gather. The IRA adopted the National Fire Protection Association levels.

Vapor Cloud Explosion

If an LNG vapor cloud with concentrations in the flammable range occurs in a confined area, e.g., within the hold of the FSRU or an LNG carrier, and is ignited, damaging overpressures may occur. An explosion occurring under this scenario could cause severe damage, but would be confined to a local area; therefore, because this type of fire would not affect the general public, vapor cloud explosions are not discussed further.

Cryogenic Effects

LNG containers are manufactured from high quality materials. LNG carriers are designed to prevent the LNG from coming into contact with the outer shell of the container or the carrier hull. International ship design rules require that areas where a leak from an LNG storage container may occur must be designed for contact with a cryogenic liquid.

Rapid Phase Transition (RPT)

This term describes the phenomenon that occurs when LNG is spilled on water, resulting in a nearly simultaneous transition from the liquid to vapor phase with an associated rapid increase in pressure. RPT may result in two types of effects: (1) a localized overpressure resulting from the rapid phase change, and (2) dispersion of the "puff" of LNG expelled to the atmosphere. This phenomenon has only been observed in experiments and has not resulted in any known incidents involving the transport of LNG.

Pool Spreading from a Spill on Water

If LNG is released, e.g., due to a rupture or hole in a Moss storage tank on the FSRU or a storage tank on an LNG carrier, several things may happen.

- Some of the LNG would immediately transition from the liquid phase to a gas on contact with warm marine air, causing RPT overpressures near the tank.
- Some of the LNG would flow out of the tank as a liquid stream and fall onto the water surface, spreading to form a liquid pool of LNG on the sea surface. Intermittent RPT overpressures would be expected below the surface, which would also generate underwater blast force sound waves.
- Intermittent RPTs would occur as wave action exposes the cold LNG to pockets of warmer water, and underwater blast force sound waves would be generated.
- Evaporation of the liquid LNG pool would begin immediately, forming a cold dense cloud of natural gas on the surface of the water like a low fog.

These physical processes would apply for a hypothetical breach or hole in the middle storage tank on board the FSRU and for a breach or hole in an LNG carrier tank. If the cloud of natural gas were ignited soon after an LNG release begins, a "pool fire" as described above would result. Physical processes associated with continued evaporation and dispersion of the gas cloud, which are important if ignition is substantially delayed or never occurs, are discussed below.

Evaporation and Dispersion from an LNG Pool on Water

If the cloud of evaporated LNG, i.e., natural gas, does not encounter a source of ignition soon after the release begins (how "soon" depends on a number of factors, but would be in terms of minutes, not seconds or hours), the vapor cloud would continue to expand and drift away from the point of release. Events that are presumed to occur are based on anecdotal evidence from witnesses to small LNG spills onto water and the physical properties of LNG and natural gas:

- Pooled LNG would continue to evaporate into a cold dense vapor cloud as it warms;
- As the vapor cloud warms, it would become less dense and increasingly buoyant and would begin to rise;

- The vapor cloud would continue to expand and move downwind at a rate that would depend on the speed and direction of the wind, as well as the wind profile; and
- The LNG pool may continue to spread, thin out, or become fragmented due to wave, wind, and current effects.

4.2.7.3 Regulations Related to the FSRU and LNG carriers

The USCG is responsible for the enforcement of all laws and regulations on U.S. flagged vessels on the high seas and all vessels within U.S. waters, which include all proposed Project activities with the exception of foreign construction and high seas portion of the towing for the FSRU to the proposed Cabrillo Port. The FSRU would be permanently moored approximately 12.01 NM (13.83 miles or 22.25 km) off the California coast. Thus, all vessels mooring there, declaring their intent to moor there, or transferring anything to or from the FSRU would be subject to boarding and control by the USCG. The USCG enforces the safety zones, keeping unauthorized vessels out of such zones to the extent that USCG resources allow. The U.S. military (including the USCG) is also allowed to take actions necessary for the protection of U.S. citizens and property from hostile acts.

After the events of 9/11, the International Maritime Organization (IMO) added Section 11-2 to the Safety of Life At Sea (SOLAS) treaty. Among the many new security measures is the requirement for certain vessels to carry Automatic Identification Systems (AIS). An AIS is a radar transponder that provides a vessel's name, location, heading, speed, cargo, and other information when struck by the radar pulse. This information is also of great help in avoiding collisions. The Applicant has indicated that each of the LNG carriers and the FSRU will be equipped with AIS.

Deepwater Port – Design and Safety Standards

The USCG Deepwater Ports Standards Division is responsible for developing and maintaining regulations and standards for fixed and floating offshore facilities engaged in oil and gas importation in Federal waters. In addition to design and safety standards, the USCG Deepwater Ports Standards Division is responsible for related issues for the license review.

MARAD and USCG's first priority under the DWPA is to ensure that LNG imports into the U.S. are accommodated safely and securely. The world's LNG fleet has operated for many years under the regulation of the USCG and other international regulatory bodies. MARAD and the USCG believe these regulations are sufficient to assure continued safe LNG vessel operations in the future. The CSLC's Marine Facilities Division also plans to develop additional design guidance and criteria for LNG terminals over the coming months.

The USCG sets performance levels that all deepwater ports must meet. At this time, the USCG is not prepared to incorporate industry standards into regulation because with rapid advances in technology, new regulations may lag and existing regulations may not fully apply to the innovations. The USCG is identifying the appropriate standards for all applications in the system concurrently with the application review process. The USCG has committed to work with the CSLC and consider any design criteria that may be appropriate. Federal criteria applicable to vessels transporting hazardous materials, including LNG, are contained in 33 CFR Subpart NN (Parts 151 to 159), and criteria for navigation safety are in 33 CFR Subpart O (Parts 160 to 169) and Subpart P (Parts 173 to 187). Regulations and impacts associated with vessel transport are discussed in Section 4.3, “Marine Traffic.”

Deepwater Port – Operational Measures for Accident Release Prevention

In addition to stringent design and construction standards, the FSRU and LNG carriers would be subject to the operational safety requirements contained in the DWPA. Current siting criteria and design, construction, and operational criteria applicable to the DWP portion of the Project are contained in a temporary interim rule issued by the USCG on January 6, 2004 (69 Federal Register [FR] 724), which amended 33 CFR Parts 148 to 150, Subchapter NN to include specific requirements for LNG facilities. These requirements include measures relating to training, development of formal operational procedures, and inspections.

Training requirements for crews of LNG carriers are specified in the IMO Seafarers' Training, Certification, and Watchkeeping Convention, and those for the FSRU are detailed in 33 CFR Part 150. A wide variety of training is included for both, including marine firefighting, water survival, spill response and clean-up, emergency medical procedures, hazardous materials procedures, confined space entry, and training on operational procedures.

Training requirements apply equally to U.S. and foreign-flagged vessels and crews. No U.S. Federal agency has the authority under the DWPA to mandate that LNG carriers calling on the FSRU or any other U.S. deepwater port be U.S.-flagged or be crewed only by U.S. citizens. Nonetheless, MARAD encourages the employment of U.S. citizens throughout the proposed Project.

Under separate statutory authority, MARAD educates and trains future merchant marine officers for various employment opportunities within the maritime industry. MARAD operates the U.S. Merchant Marine Academy and provides financial support to six state maritime academies, including the California State University Maritime Academy at Vallejo. All seven maritime academies have indicated a strong interest in expanding their curricula to include course work focused on the unique demands of the LNG trade.

Both the FSRU and the LNG carriers would be required to have formal facility operations manual covering an extensive array of operational practices and emergency procedures. LNG carriers are required by the IMO to meet the International Safety Management (ISM) Code, which addresses responding to emergency situations such as fire and LNG releases. The LNG carriers' navigational, pollution response, and some emergency procedures would also be covered in the DWP operations manual, which would address every aspect of the FSRU's operations. The minimum contents of this manual are detailed in 33 CFR Part 150. This manual would be required to be extremely detailed and specific, covering every conceivable contingency as well as normal operations. The operations manual must meet all requirements set forth by the USCG and be approved by that organization before FSRU operations could begin.

For the proposed Project, the USCG has the authority and jurisdiction to perform inspections of Project vessels in U.S. waters or on the high seas after a vessel states its intent to moor at the DWP. Additional inspections may be carried out on LNG carriers by their flag states, by classification societies, and by the owners. Per 33 CFR Part 150, the USCG also may inspect the FSRU at any time, with or without notice, for safety, security, and compliance with applicable U.S. laws and regulations.

33 CFR Part 150 mandates that the owner or operator of the FSRU inspect it every 12 months to ensure compliance with applicable safety and security laws and regulations. The results would have to be reported to the USCG Captain of the Port (COTP) within 30 days of completion and could be verified for accuracy by a USCG inspection at any time. This report would also include descriptions of any failure and the scope of repairs subsequently made. Any classification society certification or interim class certificate would also be required to be reported to the COTP as well.

LNG Carrier Security

Marine Safety and Security Requirements of Appendix C3 of this document detail the USCG operational measures applicable to the security of the Project and briefly describe the actions that the USCG would conduct to ensure the security of LNG carriers and the measures that the Captain of the Ports of Los Angeles/Long Beach would be able to take. The Captain of the Port of Los Angeles/Long Beach would use the security and safety guidelines in existence at the time the Port commences operations to determine when, where, or whether LNG carriers would be boarded or escorted. The USCG alone is responsible for the security of LNG carriers and does not anticipate using State or local law enforcement.

The USCG has established special security provisions for LNG vessels derived from an analysis of "conventional" navigation safety risks, such as groundings, collisions, propulsion, and steering system failures. These pre-9/11 precautions are conducted under the authority of port safety and security statutes, such as the Magnuson Act (50 U.S.C. 191 et seq.) and the Ports and Waterways Safety Act, as amended. These precautions include measures such as special vessel traffic controls that are implemented when an LNG vessel is transiting the port or its approaches; safety zones around the vessel to prevent other vessels from approaching nearby; escorts by USCG patrol craft; and, as local conditions warrant, coordination with other Federal, State, and local transportation, law enforcement and/or emergency management agencies to reduce the risks to, or minimize the interference from, other port area infrastructure or activities.

Since September 11, 2001, additional security measures have been implemented, including the requirement that all vessels calling in the United States must provide the

USCG with a 96-hour advance notice of arrival (33 CFR § 160.212); this was increased from 24 hours advance notice pre-9/11. This notice includes information on the vessel's last ports of call, crew identities, and cargo information. The USCG now subjects LNG vessels to at-sea boardings, where USCG personnel conduct special "security sweeps" of the vessel and ensure that "positive control" of the vessel is maintained throughout its port transit. This is in addition to the safety-oriented boardings previously described.

One of the most important post-9/11 maritime security developments has been the passage of the Maritime Transportation Security Act of 2002 (MTSA). Under the authority of MTSA, the USCG developed a comprehensive new body of security measures applicable to vessels, marine facilities, and maritime personnel. The USCG's domestic maritime security regime is closely aligned with the International Ship and Port Facility Security (ISPS) Code. Under the ISPS Code, vessels in international service, including LNG vessels, must have an International Ship Security Certificate (ISSC). To be issued an ISSC by its flag state, the vessel must develop and implement a threat-scalable security plan that, among other things, establishes access control measures, security measures for cargo handling and delivery of ships stores, surveillance and monitoring, security communications, security incident procedures, and training and drill requirements. The plan must also identify a Ship Security Officer who is responsible for ensuring compliance with the ship's security plan. The USCG rigorously enforces this international requirement by evaluating security compliance as part of its ongoing port state control program.

An additional security measure that likely would be in place is that each LNG carrier would have an exclusion zone placed around it. For example, similar carriers going in and out of the Ports of Los Angeles and Long Beach, have an exclusion zone of 1,000 yards (914 m) ahead and 500 yards (457 m) to the sides and astern of a moving liquefied hazardous gas carrier.

Major laws, regulatory requirements, and plans applicable to the FSRU and LNG carriers are presented in Table 4.2-6. A number of these marine traffic regulations are also discussed in Section 4.3, "Marine Traffic." A detailed discussion is also provided in Marine Safety and Security Requirements, which is included in Appendix C3 of this document.

4.2.7.4 LNG Carrier Accident History

The summary of major LNG carrier accidents included in Appendix C3 of this document identifies only five accidents since 1944 that occurred when LNG ships were at sea. The rest occurred when ships were in port and during loading and offloading operations. None of these accidents resulted in injuries, fatalities, or a release of LNG, and only one was the result of a collision with another vessel. In 2002, the LNG ship Norman Lady collided with a U.S. Navy submarine, the U.S.S. Oklahoma City, east of the Strait of Gibraltar. The collision occurred after the LNG cargo had been unloaded, and although dents and cracking in the hull were reported, no damage was sustained by the empty Moss-type spherical storage tanks (Smit 2005).

Table 4.2-6 Major Laws, Regulatory Requirements, and Plans for Public Safety Regarding the FSRU and LNG Carriers

Law/Regulation/Plan/ Agency	Key Elements and Thresholds; Applicable Permits
International	
International Safety Management Code	• Applicable to LNG carriers. • Section1.2.2.2 establishes safeguards against all identified risks. • Section 1.4.5 identifies procedures to prepare for and respond to emergency situations.
Federal[1]	
Deepwater Port Act (DWPA), as amended, 33 U.S.C. § 1501 et seq. *- USCG*	• Establishes the regulatory regime for the location, ownership, construction, and operation of deepwater ports beyond the State's seaward boundary.
33 CFR Part 96, Rules for the Safe Operation of Vessels and Safety Management Systems *- USCG*	• Applicable to LNG carriers. • 33 CFR § 96.240(e) states that the functional requirements of a safety management system must include procedures to prepare for and respond to emergency situations by shore side and shipboard personnel. • 33 CFR § 96.250(h) states that emergency preparedness procedures must (1) Identify, describe and direct response to potential emergency shipboard situations; (2) Set up programs for drills and exercises to prepare for emergency actions; and (3) Make sure that the company's organization can respond at anytime, to hazards, accidents and emergency situations involving their vessel(s).
33 CFR Parts 104-105 *- USCG*	• Requires vessel owners or operators to develop and submit a vessel security plan to the USCG. The format and requirements for the plan are specified in the regulations. • Requires the owner or operator of facilities that receive more that 150 passengers or more than 100 gross tons of cargo that supports the production, exploration, or development of oil and natural gas to adhere to facility security requirements specified in these regulations; conduct a facility security assessment; and develop and implement a facility security plan.
33 CFR Part 150 *- USCG*	• Describes requirements for DWP operations. • Subpart A: describes requirements for operations manuals, facility spill response plans. • Subpart B: describes requirements for inspections and notifications upon receipt of classification society certifications. • Subpart C: describes port personnel qualifications and training. • Subpart D: describes requirements for radar surveillance, tanker advisories, vessel operation within the safety zone, emergency actions. • Subpart E: describes requirements for cargo transfer operations.

[1] The US EPA has determined that Clean Air Act (CAA) Section 112(r), Risk Management Program 40 CFR Part 68 is not applicable.

Table 4.2-6 Major Laws, Regulatory Requirements, and Plans for Public Safety Regarding the FSRU and LNG Carriers

Law/Regulation/Plan/ Agency	Key Elements and Thresholds; Applicable Permits
	• Subpart F: describes inspection, maintenance, and repair requirements for emergency equipment. • Subpart G: specifies workplace safety and health requirements. • Subpart H: specifies requirements for lights and sound signals as aids to navigation. • Subpart I: specifies requirements for reporting casualties, problems with navigation aids, pollution incidents, sabotage or subversive activity, and recordkeeping. • Subpart J: describes how Safety Zones, No Anchoring Areas, and Areas to be Avoided are defined and how notice may be provided to mariners.
33 CFR Part 148, Subparts A and G *- USCG*	• Prescribes requirements for activities involved in site evaluation and pre-construction testing at potential locations that may pose a threat to human health or welfare. • Defines how the DWPA interacts with other Federal and State laws; requires construction plan to incorporate best available technology and industry practices. Defines general design, construction, and operational criteria for deepwater ports.
33 CFR Part 149, Subparts A, B, D, E, and F *- USCG*	• Describes the process for submitting alterations and modifications affecting the design and construction of a deepwater port. • Defines pollution prevention requirements for discharge containment, valves, monitoring and alarm systems, and communications equipment. • Defines minimum requirements for firefighting equipment, detection, and alarm systems. • Prescribes requirements for lighting, marking, and sound signal aids to navigation. • Prescribes requirements for construction and design standards and specifications for safety-related equipment and systems.
46 CFR Part 38 *- USCG*	• Specifies design and construction requirements for the transportation of liquefied or compressed gases whose primary hazard is one of flammability.
46 CFR Part 153 *- USCG*	• Specifies the design and construction requirements for ships transporting and storing bulk liquid, liquefied gas, or compressed gas hazardous materials.
Federal Coastal Zone Management Act Section 307(c)(3)(A) - *California Coastal Commission (CCC)*	• Requires protection against the spillage of crude oil, gas, petroleum, products, or hazardous substances in relation to any development or transportation of such materials. • Requires provision of effective containment and cleanup facilities and procedures for accidental spills that do occur.
State	
- CSLC	• Provides technical assistance to the USCG in developing design criteria and standards for the FSRU and LNG carriers.

4.2.7.5 Analysis of Accidental and Intentional LNG Releases from LNG Carriers

The design capacity of the LNG carriers that would service the FSRU would range from 36.5 to 55.5 million gallons (138,000 to 210,000 m^3). Illustrations submitted by the Applicant indicate that these carriers would hold the LNG in two or more storage tanks that would be similar to the spherical Moss storage tanks on the FSRU.

Potential initiating events for releases from LNG carriers would include shipboard fires, severe weather or sea conditions, collisions with other vessels, and intentional attacks on the carrier while it's at sea or docked at the FSRU.

The U.S. Navy has provided an opinion that it would be "virtually impossible for an errant missile from the nearby Navy Sea Range to impact the FSRU or an LNG carrier. The Navy has strict policies and procedures to maintain control of operations on the ranges. If an LNG carrier were in an area on the range where there was a potential for an errant missile to hit it, the [Navy's] operation would be postponed or relocated to avoid the carrier" (Donovan 2004).

The potential for an LNG carrier to be commandeered and used as a weapon was noted as being potentially credible in the Sandia guidance, primarily in regard to inland waterways and land-based ports. The experts attending the security workshop for the Project indicated that, given the remote location of the FSRU and LNG carriers, other targets would be more attractive. The USCG has developed post-9/11 increased security measures to prevent hijacking of any vessel carrying hazardous cargo and to provide interdiction to stop such a hijacking before the vessel could approach shore. These security provisions would be included in the Security Plan for FSRU operations, which has been developed in draft form and will be provided for review by Federal, State, and local agency staffs and elected officials with safety and security responsibilities and clearances.

Coast Guard Hazard Zones for LNG Carrier Accidents

In the USCG Navigation and Vessel Inspection Circular (NVIC), "Guidance on Assessing the Suitability of a Waterway for Liquefied Natural Gas (LNG) Marine Traffic" (USCG 2005), the USCG evaluates potential impacts to the public from LNG carrier incidents based on three hazard zones developed by Sandia National Laboratories (Sandia 2004). The hazard zones were developed based on releases of LNG from carriers due to intentional acts, which were determined to produce larger spills than accidental releases and address primarily inland waterways and onshore ports.

One of Sandia's key assumptions in developing the zones of concern was that the potential for a pool fire from an intentional breach would be likely because of the high probability that an ignition source would be available for many of the initiating events identified; however, certain risk reduction techniques could be applied to prevent or mitigate initiating events. In some instances, such as an intentional spill without a tank breach, an immediate ignition source might not be available and the spilled LNG could therefore disperse as a vapor cloud; if an ignition source were subsequently encountered, the result would be a vapor cloud (flash) fire, which would burn back to the source and terminate in a pool fire. Pool fires were estimated to last between 5 and 20 minutes in duration (Sandia 2004, 151). The Sandia guidance does not provide its assumptions about the capacity of individual cargo tanks or the total capacity of the LNG carrier.

USCG determined that hazard zones were not applicable to the proposed Project because they were developed for harbors and ports. In addition, the Project-specific modeling for the FSRU accounted for potential incidents at the LNG carriers because it included the maximum volume of LNG that could be present on an LNG carrier and FSRU when the LNG carrier was docked.

Worst credible case impacts for an incident involving an LNG carrier were not separately modeled for the proposed Project because such carriers would come no closer to shore than the FSRU location and such impacts are not expected to be larger than those calculated in the IRA for large releases from the FSRU for reasons previously stated.

4.2.7.6 Impact Analysis and Mitigation

Risk Assessment Process for FSRU LNG Operations

The site-specific IRA completed in support of this document applies only to the proposed Project FSRU at its proposed offshore location. The results and conclusions from that assessment do not apply to any other offshore or onshore LNG import and regasification facility.

The number of LNG facilities is relatively small, and there have been too few incidents to provide an adequate statistical basis regarding potential failures or release consequences for these types of facilities. Incident reports from similar facilities are, however, helpful for this discussion regarding accident scenarios and for generally characterizing potential hazards, but do not provide enough information to develop an estimate of risk. A chronological list of accidents involving LNG is included in Appendix C3 of this document.

The potential risks to public safety from the FSRU were developed using the following steps:

- An IRA team was formed, including technical professionals with special expertise in marine operations and safety, security, risk communication, risk analysis, computer modeling, and LNG facility design and operation;[2]
- The IRA Team first identified the hazardous properties of the cryogenic liquids and gases that would be stored or transported;

[2] The following information is presented in response to a comment. The services of an epidemiologist were not necessary to estimate the potential risks. Epidemiologists, by definition, study aspects of mass exposures and transmission of diseases. Public safety concerns in the event of an LNG incident/release are related to potential exposures to a cryogenic liquid, a gas that is an asphyxiant at high concentrations, blast forces, and the acute (immediate) effects of radiant heat if a natural gas cloud is ignited.

- The team then identified the scenarios that could lead to a release of LNG based on public scoping comments, two intensive workshops (discussed below), an independent review of the Applicant's conceptual design and operations and safety plans and operational procedures, and an independent review of the Applicant's confidential security and safety plans and emergency procedures;
- Oceanographic and meteorology experts collected and summarized site-specific weather and ocean conditions for the proposed Project location offshore, to provide a basis for discussions about the potential impacts from various scenarios;
- In a parallel effort, marine operations and risk professionals collected and analyzed marine traffic numbers and patterns to identify the types and tonnage of marine vessels transiting waters near the proposed FSRU location;
- The team then screened out scenarios that were too unlikely to occur (no plausible initiating event, or no sequence of events that would result in a release) or that would not result in impacts outside of the immediate vicinity of the FSRU (the safety zone) (scenarios that did not appear to have any potential for causing impacts to the public);
- Using site-specific meteorology and ocean conditions to help define some of the parameters, and local marine traffic data to define the types of vessels that might be most likely to collide with the FSRU, the team then conducted computer modeling for incident scenarios that were brought forward to identify the potential consequences or impacts from worst credible case and other plausible scenarios;
- In another parallel effort, marine and risk specialists developed estimated frequencies for ship collisions; and
- Finally, the team combined the consequence results with the frequency information to estimate the potential risks for each scenario.

Security Vulnerability Assessment and Hazard Identification

On behalf of the CSLC, the USCG, and MARAD, Ecology and Environment, Inc., (E & E) sponsored a security and vulnerability assessment (SVA) workshop and a hazard identification and analysis (HAZID) workshop for the proposed Project. The purpose of the workshops was to identify and analyze potential hazards related to the proposed Project. The workshops represent one component of the early agency consultation process the Project team used to identify issues to be addressed in the October 2004 Draft EIS/EIR. The Project team invited Federal, State, and local agencies to nominate representatives with expertise in key disciplines such as engineering, hazard response, marine transportation, terrorism, fire protection, emergency response, security, safety, and risk-related expertise to attend and participate in the workshops.

More than 55 technical specialists and engineers were invited to attend the workshops. In addition to the EIS/EIR team, 21 agency participants attended the SVA workshop, and 17 agency participants attended the HAZID workshop. These participants included representatives from the City of Oxnard, Port of Long Beach, the CSLC, the CEC, the CPUC, the CDFG, the USCG, the U.S. Department of Energy, and the Federal Bureau of Investigation. Representatives of the Applicant and SoCalGas also attended specific sessions to answer questions about the design and operations of the proposed Project.

The one-day SVA workshop was held on April 5, 2004. The Applicant provided a general overview of security measures planned for the proposed Project and was then excused from further participation in the SVA workshop. The workshop participants then explored a wide range of potential security threats along with current and potential preventive and mitigative risk-reduction measures.

Following the SVA, the EIS/EIR team held a three-day HAZID workshop on April 6–8, 2004, to identify safety and environmental hazards, focusing on those concerns that could potentially affect members of the public. A representative from the University of California at San Diego's Scripps Institution of Oceanography provided an introduction to offshore meteorology conditions in the vicinity of the proposed DWP location. The Applicant described specific systems and operations of the proposed facility to familiarize the workshop participants and was then excused from further participation in the workshop sessions. A consensus listing of accident scenarios was recorded, which formed the basis of the IRA for the proposed DWP. The workshop team evaluated the following systems associated with the proposed Project:

- Cargo systems;
- Marine systems;
- Support/utility systems;
- Onshore pipeline;
- Turret/swivel;
- Position mooring system;
- Subsea pipeline/riser;
- Hull structure;
- Installation/hookup/commissioning;
- Loading (from LNG carrier);
- Gas send out;
- Shutdown systems; and
- External events.

The workshop participants also discussed concerns identified through the public scoping process, including various terrorist scenarios, e.g., use of airplanes from local airports or shoulder-fired missiles to attack the facility, or LNG-vessel hijacking, the potential for catastrophic and smaller LNG releases due to equipment failure and human error, the integrity of the offshore and onshore pipelines, accidents involving other vessels, earthquakes, emergency response, validation of computer modeling, and other topics.

The security and vulnerability and hazard identification workshops focused on identifying and documenting possible security threats and accidental hazards that potentially could impact the public and/or environment. Representative examples of the threats that were considered include delivery of a bomb by small craft; use of a commercial airliner, fixed wing airplane or helicopter to strike the FSRU; a diver assault with a shape charge to the FSRU; and an intentional release of LNG. Each threat was evaluated as to its likelihood of success and the nature of the potential damage it could cause.

Some events were not considered further. The possibility of a deliberate attempt to disconnect the FSRU from its mooring was considered not to be credible because intentional disassembly of the mooring system would require heavy equipment and/or demolition support and would be detected and intercepted by the crew of the FSRU or the one or two boats patrolling the safety zone with enough time to deter the attack. Similarly, the takeover of an LNG carrier or a deliberate collision of an LNG carrier with the FSRU was not considered credible due to recent changes in security in the marine industry and the fact that LNG carriers would be in frequent communication using secure channels, making early detection of an attempted takeover very likely.

Representative events that were evaluated during the hazard identification workshop included an LNG spill overboard, loading arm failure, the presence of an ignition source in the submerged combustion vaporizers, a ship collision with the FSRU, a ballast system malfunction, and fires on LNG carriers or the FSRU. The group evaluated the potential consequences of each event using a structured process, reviewed any existing safeguards, and prepared recommendations and comments. One event that was evaluated was the potential for the FSRU to lose one or more mooring lines or become disconnected from the mooring system as a result of an operational incident, which could result in drifting of the FSRU toward the shipping lanes or shore. This event was considered to be very unlikely, due to visual inspection to detect failed mooring lines, the availability of at least one standby tugs to rescue the drifting FSRU, and response by the USCG.

The technical information provided with the FSRU's design concept was adequate for purposes of hazard identification, but as discussed in Section 2.2.2, "Floating Storage and Regasification Unit," the design has not been finalized and would be subject to further review. An underlying assumption was that the classification rules, USCG rules, and standards of practice would be met.

2004 IRA and Sandia National Laboratories Review

Based on the results of the security and hazard identification workshops discussed above, five main scenarios and several variations were identified for consequence analysis of LNG spills. They represented a range of both accidental and intentional events that could produce breaches of the LNG tanks and ranged from several smaller but potentially more frequent events to the simultaneous release of the entire contents of all three LNG storage tanks on the FSRU. The 2004 IRA concluded that none of the releases would produce consequences to the public, for example, at either the coastwise TSS or the shore.

As discussed in Section 4.2.3, "Independent Risk Assessment and Sandia National Laboratories Review," the 2004 IRA of the DWP was prepared prior to the December 2004 publication of the Sandia National Laboratories (Sandia) report entitled "Guidance on Risk Analysis and Safety Implications of a Large Liquefied Natural Gas (LNG) Spill Over Water" (Sandia 2004). The USCG commissioned the authors of the Sandia guidance report to conduct a third-party technical review of the 2004 IRA. "The goal of Sandia's technical evaluation of the Cabrillo Port IRA was to assist the USCG in ensuring that the hazards to the public and property from a potential LNG spill during transfer, storage, and regasification operations were appropriately evaluated and estimated" (Sandia 2006).

The 2006 Sandia report (Appendix C2) summarizes the results of the Sandia review of the 2004 Cabrillo Port IRA and supporting analyses. The results of the Sandia review, the additional analyses and evaluations conducted, and the resolutions of suggested changes are included in the 2006 IRA (Appendix C1).

Table 4.2-7 summarizes the major issues identified by Sandia and the general resolution by the Technical Review Panel. The changes have improved the hazard analyses and provide results that adequately and reasonably represent the hazards and public safety issues associated with maritime LNG import operations at the Cabrillo Port, relative to the current understanding of large LNG spills over water"(Sandia 2006).

Table 4.2-7 Summary of Issues and Resolutions Identified in the Cabrillo Port IRA

Identified Issue	Resolution
General Issues	
A two-tank release appears to be the most severe event based on potential credible threats.	Hazard analyses were modified from a catastrophic three-tank release to a more credible two-tank release.[a]
Evaluation of hazards to on-shore public from a spill as well as shipping, recreational boaters, etc. should be considered.	Assessment of the potential impacts of fire and dispersion hazards on shipping and other receptors will be considered.
Reassess intentional threats at regular intervals because of continually changing nature of threats.	CSLC and USCG are considering an appropriate interval to assess changes or escalation of credible threats.
Accidental and Intentional Breach and Spill Issues	
Accidental breach and spill results from a collision appear appropriate and consistent with other collision studies.	Agree with overall approach and results.
Credible threat analyses suggest breach sizes in the range of 7-12 m^2 should be considered for this type of facility and location.	One event includes the possibility of the breach of two tanks with up to a 7 m^2 hole in each tank. The other event suggests the possibility of a breach of one tank of up to 12 m^2.

Table 4.2-7 Summary of Issues and Resolutions Identified in the Cabrillo Port IRA

Identified Issue	Resolution
A simultaneous breach of all three storage tanks appears inappropriate to use for hazard analyses.	Breach and spills were reassessed for a two-tank breach and spill.
Risk management of the final design should include the assessment of active mitigation measures due to the remoteness of the system.	USCG will encourage and assess mitigation measures and systems in evaluating the final FSRU operational plan and design.
Fire and Vapor Dispersion Hazard Issues	
The analytical technique employed for dispersion calculations in the IRA is sensitive to domain scale and boundary conditions and must be carefully assessed.	Domain scale and boundary conditions were reassessed and identified problems were addressed with more detailed analysis, comparison with other numerical approaches, and validation with experimental data.
Initial IRA calculations for potential dispersion distances appeared to under predict hazard distances.	Dispersion scenarios were analyzed using more appropriate input parameters, computational domains, and boundary and site-specific environmental conditions. The final results obtained were consistent with results from other numerical models.
General application of the modeling technique used in the IRA for dispersion calculations and hazard estimates should be reviewed for appropriateness.	The selected analytical approach was carefully reviewed and evaluated against experimental data and found to provide results consistent with best available computational fluid dynamics methodologies.
Fire hazard evaluations were not included in the initial draft IRA. Since the likelihood of ignition of a large spill is possible, fire hazard analyses should be conducted.	Fire hazard analyses were developed using appropriate large-scale fire modeling analytical approaches. The results obtained are consistent with other large-scale LNG fire analyses for spills over water.
Process Safety and Security Issues	
While current processing operations appear to preclude a multi-tank breach, final system design and safety features should be carefully evaluated.	The USCG to carefully evaluate implementation of improved safety and security measures to reduce the risks and consequences of off-normal events during post-license detailed design review.
Final system safety analysis unable to be completed until conceptual handling, storage and regasification system design and operational parameters finalized.	The USCG to carefully evaluate implementation of improved safety and security measures to reduce the risks and consequences of off-normal events during post-license detailed design review.

Source: Sandia 2006.

Note:

[a]After completion of the analyses recommended by Sandia, and based on information regarding insulation provided by Sandia, a cascading multiple (two or three) tank releases were evaluated.

Sandia reviewed the scenarios studied in the 2004 IRA and recommended that the proposed breach and spill conditions be reassessed, stating that “more credible threats exist and may be more likely than the catastrophic total release scenario originally considered in the Cabrillo Port IRA” (Sandia 2006). Sandia agreed to discuss their findings to date on cascading issues including foam insulation degradation and to provide open access information on ship impact analysis and intentional event threat analysis that could be used to formulate scenarios for consideration in the 2006 IRA.

Sandia (2006) found that the three-tank simultaneous release was not a credible:

> The intentional breach analysis originally in the IRA considered only a catastrophic, simultaneous, three-tank release, which may be unrealistic based on the current understanding of credible events, as identified by intelligence agencies and the Department of Homeland Security (DHS). Therefore, Sandia recommended that the intentional threats be reexamined based on emerging guidance from DHS and from the intelligence community and noted in the recent Sandia report and the associated classified report on possible intentional threats.

Sandia evaluated the potential size of breaches of the FSRU based on a range of possible credible threats. The exact type and scale of these threats is discussed in a recent classified report by Sandia, but included a range of insider and external attacks from sea and air with a range of weapons. Based on considering this range of threats and the physical characteristics of the FSRU, including hull and storage tank design and standoff, Sandia suggested a range of potential hole-sizes to use for spill and dispersion analyses; however, a massive LNG release in a short time period was not considered to be credible.

2006 Independent Risk Assessment

The IRA studied several scenarios involving the release of LNG to the marine environment in the immediate vicinity of the FSRU, including vessel collisions and intentional events. Based on the technical review conducted by Sandia and on current knowledge and modeling techniques for collisions, breaches, and potential spills for double-hulled vessels, the following scenarios were addressed in the IRA. Each of these is explained in the IRA, including a description of the scenario, consequence modeling, and frequency estimation, where applicable:

- Accidental explosion in hull void;
- Accidental explosion in Moss tank;
- Accidental explosion between vessels;
- Intentional two Moss tank breach;
- Accidental/intentional cascading multiple (two or three) Moss tank release (escalation); and
- Accidental/intentional marine collision.

Table 4.2-1 on page 4.2-2 presents the IRA's summary of FSRU accident consequences. Table 4.2-8 provides information regarding the scenarios that Sandia recommended for analysis and shows the number of storage tanks breached, the events that could lead to the breach, the total LNG spilled, and the size of the breach assumed for each tank. Sandia concluded, ". . . the accidental breach scenarios and analyses for the FSRU were reasonable relative to the current knowledge and modeling techniques for collisions, breaches, and potential spills for double-hull vessels" (Sandia 2006).

Table 4.2-8 Scenarios Evaluated in the 2006 Sandia Report and the IRA

Event Initially Recommended for Consideration by Sandia	Scenario Considered in the IRA	Storage Tanks Breached Sandia/IRA	Assumed LNG Volume Spilled (m^3) Sandia/IRA	Area of Breach (m^2) per Tank Sandia/IRA
Collision with large ship at speeds approaching 20 knots, puncture of single LNG storage tank, assumes striking vessel does not plug puncture	Determined to not be governing event	1/NA	100,000/NA	20/NA
Collision with a large ship causing circumferential rupture of single LNG storage tank	Marine collision	1/1	50,000/50,000	1,013/1,300
Collision with a large ship at speeds of 20 knots, puncture with plugging by vessel	Addressed by marine collision scenario (above)	1/NA	50,000/NA	5/NA
Off-normal processing event that causes breach of LNG storage tank near deck level	Determined not to be a governing event	1/NA	50,000/NA	10/NA
Single large intentional event	Determined not to be a governing event	1/NA	100,000/NA	12/NA
Multiple large intentional event – simultaneous	Intentional two Moss tank breach (simultaneous)	2/2	200,000/200,000	7 (1st tank), 7 (2nd tank)/same
Multiple large intentional event – escalation[a]	Accidental/intentional cascading multiple (two or three) Moss tank release (escalation)	NA/2 or 3	NA/100,000 (2 tanks) 200,000(3 tanks)	NA/7(1st tank), 1,300 2nd tank, 1,300 3rd tank

Notes:
Adapted from Sandia 2006.
NA = not applicable.
[a]This scenario was added with Sandia's concurrence based on the results of its analysis.

Of the six scenarios analyzed in the IRA, the first two and the accidental explosion between vessels are limited in scope and were determined to not affect the general public; therefore, they are not discussed further in this section, but details are provided in Appendix C1. Evaluation of the first scenario (accidental explosion in a hull void) determined that it produced only a localized effect. The second includes representative accidents that would affect only one tank that could have a number of causes. For example:

> Overall, the processing system layout and safety considerations in the conceptual design suggest that the potential threats from off-normal events in the

processing area would probably impact initially only one FSRU storage tank Sandia (2006).

Similarly, the accidental explosion between the vessels did not cause a breach of an LNG storage tank and is not discussed further.

Sandia agreed that the Intentional two Moss tank breach scenario was the case that resulted in the greatest distance to the lower flammable limit. Because of timing issues and the fact that the results of other scenarios initially identified by Sandia were believed to be bracketed by the marine collision and intentional/accidental scenarios, Sandia agreed to the final scenarios.

The intentional two Moss tank breach (a simultaneous release of LNG from two tanks) was calculated to have the potential to affect the greatest distance from the FSRU with a vapor cloud (flash) fire resulting from dispersion. The escalation case involving failure of all three cargo tanks produces the greatest distance at which serious injuries from a pool fire could occur; these results are discussed in more detail below. No vapor cloud dispersion or vapor cloud (flash) fire would result from the escalation case since immediate ignition is presumed for this scenario.

The evaluations identified two governing intentional events that should be considered for spill and hazard analyses. One event includes the possibility of the breach of two tanks with up to a 7 m^2 hole in each tank. The other event suggests the possibility of a breach of one tank of up to 12 m^2. These events may not lead to the full release of all the LNG from each tank, but for conservative estimates of hazard distances, full tank volume releases could be assumed.

Although it is not one of the governing cases, the marine collision scenario is summarized below because it has the potential to affect one of the vessel traffic lanes. Since the consequence distances were found to be less than those for the intentional event, the other marine collisions initially recommended by Sandia were not analyzed.

The worst credible case scenario involved an intentional event resulting in the release of 53 million gallons (200,000 m^3) of LNG to the ocean surface. As discussed in Section 4.2.7.2, “LNG Risk-Related Scenarios,” subsequent to the release, there would be three likely potential consequences: a pool fire, vapor cloud dispersion with no ignition, or a vapor cloud (flash) fire.

Pool Fire. Under the escalation scenario, a release of 53 million gallons (200,000 m^3) of LNG would form a pool on the ocean surface approximately 0.4 NM (0.5 miles or 0.8 km) in diameter. The entire amount of LNG stored on the FSRU is not released because with immediate ignition, some of the LNG would remain in the storage tanks instead of spilling out. This scenario addresses both an intentional event and an accident in which one tank is breached causing one or both of the others to fail. For example, Sandia concluded that “…the processing system layout and safety considerations in the conceptual design suggest that the potential threats from off-normal events in the processing area would probably impact initially only one FSRU storage tank"(Sandia 2006).

Beyond the limits of the pool, methane would be present in the atmosphere above the ocean surface. Assuming ignition of the gas would occur at the time of the release, computer modeling calculates that a pool fire capable of causing injury to a person, i.e., a heat flux value of 5 kW/m^2 or greater, could occur at a distance of about 1.7 NM (2.0 miles or 3.2 km) from the FSRU.

This distance is less than the proposed Area to be Avoided (ATBA) of 2 NM (2.3 miles or 3.7 km) around the FSRU. Therefore, under this scenario a pool fire would not be expected to impact either the nearest point on the mainland or the nearest marine vessel traffic lane, the closest of which is about 2 NM (2.3 miles or 3.7 km) from the FSRU. Sandia noted that it results are in close agreement with the results from the IRA, and concluded that "The model used is appropriate given the absence of obstacles. The assumptions made are reasonable given the current knowledge of the required input parameters and should provide a conservative estimate of thermal hazard distances."

Vapor Cloud Dispersion. Dispersion modeling was used to determine the distance from the FSRU at which a vapor cloud, having a methane content of at least 5 percent and therefore in the flammable range, would extend under three different wind speeds, i.e., 2, 4, and 6 meters per second (m/s) (4.5, 8.9, and 13.4 mph or 7.2, 14.4, and 21.6 km/hr). These wind speeds were selected as they represent the typical lower, average, and upper velocities experienced in the vicinity of the FSRU based on available weather data from a nearby buoy.

For the worst credible intentional or accidental event release of 53 million gallons (200,000 m^3) from two tanks of LNG, it was determined that a wind speed of 2 m/s (4.5 mph) resulted in the worst case in which the flammable vapor cloud extended about 6.3 NM (7.3 miles or 11.7 km) downwind from the FSRU. (Higher wind speeds would cause the gas to dissipate more quickly to below the lower flammable limit; therefore, the potential impact distance would not be as great.) If the wind were blowing toward the northeast, the vapor cloud would not reach shore but would extend across both the Southbound and Northbound Coastwise Traffic Lanes.

For this same scenario, Sandia's results were significantly less than those calculated in the IRA—about 7,000 m versus about 11,000 m. Sandia attributes this to differences in the size and speed of computing power:

> The 2-tank, 7-m^2 hole case was performed by ACE with a relatively coarse, stretched mesh with a minimum of 20 m width cells in each direction. Sandia performed a simulation of this case using FDS but with a finer uniform mesh, 10 m cell widths in each direction for a total of 22.4 million computational cells, and found results for vapor dispersion to be somewhat less than the ACE results. Thus, the final result from ACE for 2-tank, 7-m^2 hole case appears to be reasonable and should provide a conservative estimate of dispersion distances.

For purposes of transparency, and to permit members of the public to replicate the analysis if desired, the lead agencies directed the consulting team to use only models that are in the public domain, and that could be run without extraordinarily large or fast computing power. Thus, the IRA modeling overestimates the impact distances when compared with Sandia's results due to differences in the computational cell resolution.

Further, Sandia confirmed that the Fire Dynamics Simulator (FDS) is an appropriate model for dispersion analysis:

> FDS simulations performed by Sandia to date, as well as evaluation of the mathematical models of the code indicate that FDS is capable of simulating LNG dispersion, but a large number (10 million to 100 million) computational cells are required. It would be optimum to perform these dispersion simulations with finer resolution, however lower resolution simulations result in longer distances to lower flammable limit due to the turbulent mixing being under resolved. Therefore, the current FDS analyses provide a conservative assessment of safety hazard distances.

Vapor Cloud (Flash) Fire. A vapor cloud fire could occur if the released LNG were to evaporate and disperse downwind before encountering an ignition source but then was subsequently ignited. The fire would be expected to burn back to the FSRU. Again, under the worst case wind conditions of 2 m/s (4.5 mph or 7.2 kph), computer modeling indicated that a vapor cloud fire capable of causing injury to a person, i.e., a heat flux value of 5 kW/m^2 or greater, could extend 6.3 NM (07.3 miles or 11.7 km) from the FSRU approximately 60 minutes after release the LNG release occurred. This vapor cloud (flash) fire would occur within the proposed ATBA and would not impact the nearest marine vessel traffic lanes; also, it would not affect persons on the mainland shore 12.01 NM (13.8 miles or 22.2 km) away.

The IRA concluded that impact distances from accidental releases and intentional events would not reach the nearest shoreline and that the members of the public who would be at risk would be those in the vicinity of the FSRU or in the coastal shipping lane, approximately 2 NM (2.3 miles or 3.7 km) offshore. The IRA recommended specific mitigation measures to reduce the risks to as low as reasonably practical. The IRA's recommendations are incorporated into the mitigation measures below.

The IRA considered a scenario in which a large marine vessel, e.g., container ship, oil tanker, or passenger ship, collided with the FSRU resulting in the breach of a Moss tank aboard the FSRU. The analysis involved the instantaneous release of 50 percent of the volume of one tank, or about 13.2 million gallons (50,000 m^3) of LNG. A spill of this volume would form a pool of LNG having a maximum diameter of 2,395 feet (730 m). If this pool encountered an ignition source before dispersion were to occur, the resulting distance to the minimal thermal radiation threshold of 5 kW/m^2 would be 1.6 NM (1.8 miles or 3 km). This distance extends beyond the 1,640-foot (500 m) safety zone but would be within the 2 NM (2.3 miles or 3.7 km) from the FSRU ATBA and would not impact the shipping lanes.

If the LNG were to evaporate and disperse before encountering an ignition source then, using a worst case wind speed of 2 m/s (4.5 mph or 7.2 km/hr), the outer boundary of the lower flammable limit (5 percent methane) would extend approximately 2.9 NM (3.3 miles or 5.3 km) downwind. Therefore, an area beyond the ATBA would be impacted including one of the two shipping lanes. However, it would take approximately 28 minutes for the vapor cloud to reach the closest shipping lane and 55 minutes to dissipate below the lower flammability limit, and it would take 50 minutes for the vapor cloud to reach its maximum extent. Vessels in the area could be notified during this time.

The potential frequency of a collision of a large marine vessel with the moored FSRU that would cause the breach of an LNG storage tank was estimated to be 2.4×10^{-6}, i.e., one occurrence every 417,000 years, based on information regarding the numbers and sizes of large vessels that might be transiting near the FSRU (see Section 4.3, "Marine Traffic," and the IRA in Appendix C1 for a more detailed discussion).

The IRA states that the proposed Moss tank demonstrates a very robust design against marine collisions. Only vessels with very specific geometry, strength, and speed would have the physical capacity to penetrate the hull's structural steel and breach the cargo containment. The IRA states that the frequency estimation for the accidental marine collision scenario is a conservative overestimate and that the scenario is improbable.

Sandia reached a similar conclusion regarding the FSRU:

> The FSRU, which is a double-hull vessel design, makes it particularly robust for normal collisions or ship accidents. Based on the FSRU double-hull design, which provides even greater standoff between the storage tanks and the outer hull than a typical LNG vessel, the identified collision events and the suggested breaching results appear reasonable relative to other double hull tanker collision studies using similar analysis methods and threats. Therefore, the spill and breach conditions suggested for LNG transfer and handling appear reasonable and appropriate.

In summary, of the scenarios studied, the IRA determined that the greatest distance from the FSRU within which public impacts would occur is 6.3 NM (7.3 miles or 11.7 km), which would result from the intentional breach of two Moss tanks. This hazard distance encompasses the TSS shipping lanes, but extends no closer than 5.71 NM from the nearest mainland landfall. The hazard to the shipping lane would occur about 30 minutes after the initiating event, which could allow for notification and response. The exposure time within the shipping lane would be for about another 30 minutes until the vapor cloud dispersion falls below the lower flammability limit. An average of three vessels would be exposed to this vapor cloud hazard based on marine traffic frequency estimates.

Pool fire hazards were not predicted to reach the coastwise shipping lane. An escalation event resulting in the cascading breach of three Moss tanks with subsequent pool fire would produce an injury level threshold that would reach 1.7 NM (2 miles or

3.2 km) from the release point at the FSRU. Although considered a credible intentional or accidental event, more likely scenarios would result in smaller pool fire hazards, e.g., 1.6 NM (1.8 miles or 3 km) for the marine collision scenario, and 1.4 NM (1.6 miles or 2.6 km) for the intentional two Moss tank breach.

Sandia reviewed all of the scenarios and modeling results and concluded:

> Overall, the final results for both fire and dispersion hazard distances, after incorporating the recommended Sandia changes, appear to provide reasonable estimates of hazard levels and distances for what are considered credible events. The analyses developed should provide conservative estimates of expected hazard distances (Sandia 2006).

Table 4.2-2 above summarizes the hazards and threats that were considered and how they were evaluated in the public safety analysis.

Significance Criteria

A public safety impact from FSRU operations would be considered significant and require mitigation if Project would result in any of the following adverse effects:

- Cause a loss of life or serious injury to people other than those employed by the Project; or
- Cause significant damage (major and long term or permanent) to one or more of the environmental resources discussed in this document.[3]

Impacts and Mitigation Measures

The determination of an impact's significance (described in Section 4.1.5, "Applicant Measures and Mitigation Measures") includes assigning an impact class (Classes I through IV) based on the potential adverse effect and the potential duration of the adverse effect, e.g., temporary, short-term, long-term, or permanent. For public safety impacts, the determination of an appropriate class for each impact is based solely on the potential for causing serious injury or fatality to a member of the general public, even if such impacts were unlikely to occur. Class I impacts are defined as those for which a significant adverse effect remains even after mitigation. The highest priority for developing mitigation measures is to prevent accidents, and then to ensure appropriate response should an accident occur. Most of the Class I impacts discussed below are accidents or other unanticipated releases that have a very low probability of occurring. If such impacts were to occur, however, the consequences would be significant according to the conservative criteria identified.

[3] The specific significance criteria for evaluating the consequences of accidents pertinent to each environmental resource are discussed in subsequent environmental resource sections of this document.

A discussion of the differences between Applicant-proposed measures (AM) and agency-recommended mitigation measures (MM) is provided in Section 4.1.5, "Applicant Measures, and Mitigation Measures."

Impact PS-1. Potential Minor Release of LNG due to Operational Incident or Natural Phenomena at the FSRU or an LNG Carrier

An incident at the FSRU or LNG carrier due to human error, upsets, or equipment failures, or as a result of natural phenomena (severe wave conditions, high winds, etc.) could cause a release of LNG from the FSRU or an LNG carrier that would have a limited area of effect (Class II).

Operational accidents of varying levels of severity occur at all types of processing facilities and at facilities where materials are transferred from one container to another. The stringent design requirements that would be imposed on the FSRU and on any newly constructed LNG carriers are intended to provide inherent engineered safety features for these vessels and equipment that reflect the type and magnitude of site-specific seismic, sea, and weather conditions to which the FSRU, its moorings, and pipeline connections might be subjected. In addition, USCG regulations and international and class certification requirements mandate that the Applicant develop detailed plans to address all aspects of facility operation, security, and emergency preparedness and response; these plans would be reviewed by relevant agencies that would also conduct compliance inspections. These requirements are discussed in more detail in Marine Safety and Security Requirements in Appendix C3 of this document. For example, a detailed discussion of the minimum requirements for emergency planning and emergency exercises and drills is discussed as part of the mitigation measures contained in Section 2.1 of the Marine Safety and Security Requirements in Appendix C3. The following plans, for example, would be developed and implemented:

- *Deepwater Port Operations Manual*, prepared in accordance with 33 CFR § 150.15 and the International Safety Management Code;
- LNG carriers would be required to have a *Vessel-Specific Emergency Response Manual* on board, in accordance with 33 CFR § 96.250(h). The manual would contain procedures concerning training and drills relating to identifiable risks so that vessel personnel are capable and competent to manage all emergency situations. Relevant equipment would be ready for use, and personnel would be familiar with and confident in its use. This also includes procedures for spills, fires, groundings, and personal injuries.
- *Emergency Procedures Annex to the Operations Manual*, prepared in accordance with 33 CFR § 150.15(p). This annex would require periodic emergency drills and exercises and address contingency response procedures for all emergency incidents, including fire, reportable product spill, personal injury, or terrorist incident;
- *Deep Water Port Security Plan* prepared in accordance with 33 CFR § 150.15(v); and

- *Coast Guard Spill Response Plan* would be prepared for LNG tankers and support vessels.

Agencies that would be responsible for detailed review and inspection of the proposed Project design, construction, and operation are identified above in Table 4.2-3 above. Responsible Federal, State, and local agencies would be involved in all phases of the proposed Project design, construction, and operation.

The USCG responds to emergencies offshore. Should an incident involving the FSRU or an LNG carrier occur, the relatively large distance from shore would be expected to allow sufficient time for notification and mobilization of emergency response resources, such as additional tug support and fireboats, to ensure that public safety is not affected. The Applicant has incorporated the following measures into the proposed Project to reduce the potential of incidents due to operational errors, upsets, or equipment failures or natural phenomena:

AM PS-1a. Applicant Engineering and Project Execution Process. The Applicant would undertake—regardless of any less stringent regulatory requirements—the following steps to design, build, and operate the proposed Project:

1) Prior to final internal Project funding, undertake a full Front End Engineering Design (FEED) exercise with a suitably qualified and experienced contractor under the management of an Applicant technical team. This would define the engineering requirements for the complete Project and identify sources for all remaining detailed information and data, to be ready for internal Project sanction and final detailed engineering.
2) Undertake a comprehensive offshore site survey to determine bathymetry, geology, and geotechnical characteristics of the area in and immediately around the locations of each element of the Project. This would require mobilization of specialized marine vessels and crews to perform the acoustic surveying and soil coring for the shallow water horizontal directional boring (HDB) of the pipelines crossing under the beach to the FSRU mooring in deep water. The survey results would provide additional information for the final detailed design of the HDB, pipelines, cable crossings, pipeline end manifolds, and mooring system anchors.
3) Fully implement the proposed Project under a self-imposed "Safety Case" process for the detailed design of the proposed Project. This would begin with the FEED but could be completed only when the level of the facility definition is in the advanced detailed design phase. This would require a complex series of additional detailed safety checks and balances be put into place, including HAZID, hazard and operability studies

(HAZOPs), quantitative risk analyses (QRAs), formal safety analyses (FSAs), and associated safety engineering exercises such as process plant modeling and analyses. This would be finalized during the detailed design of the FSRU safety systems, the process plant and deck layouts, and the associated systems such as piping and utilities, and the control systems and procedures. Upon startup, the safety case would become a “living tool” for the facility operating team—one that would be updated and reanalyzed as needed based on operational experience—to ensure that the proposed Project meets or exceeds required standards during all phases of operation.

4) Upon internal Project sanction/funding, ensure detailed engineering would be conducted for all components by suitably qualified and experienced contractors under the management of an Applicant technical team and in accordance with demanding technical requirements that would be carefully defined in contractual documents. The selected qualified engineering contractors would likely be different for the contractor designing the hull, regasification topsides, mooring, pipelines, etc. Using this process, the Applicant would ensure that all engineering is executed to meet or exceed the regulatory and Applicant’s internal requirements.

5) Commission a series of model tests of the FSRU facility at an experienced and well-established model test basin. More advanced detailed theoretical analyses would be completed first to identify the governing criteria and cases to be modeled in the basin. These model tests would cover both the survival sea states without an LNG carrier moored alongside and the operational sea states with the carrier moored alongside the FSRU. FSRU motions and mooring system loads would be measured under survival storm conditions to confirm the calculated results. Similarly, relative and absolute motions of and between the FSRU and the berthed carrier would be measured to confirm the operability limits of the berth mooring, fender, and loading arm systems. This would also provide information about FSRU motions for the detailed design of the topsides equipment.

6) The Applicant would require independent third-party verification of detailed engineering, procured equipment, fabrication, construction, and offshore installation and commissioning of all Project components. Where such independent third-party verification would be required by a regulatory agency, or in order to obtain class certification, a single verification process would be conducted to ensure efficiency of this verification.

7) During the construction phases of the proposed Project, both quality and safety audits at major fabrication/ construction sites would be undertaken by the Applicant to ensure quality and safety of the Project components. Actual safety and quality performance during construction would be a contractual obligation for the various contractors selected by the Applicant.

8) Before releasing the FSRU from its inshore commissioning, i.e., before towing to the proposed Project site, and after offshore installation of all components, but before facility startup, the Applicant would conduct a formal pre-startup review. The status of the facility, quality assurance, "outstanding items," operational preparedness, and compliance with legal and regulatory commitments would be carefully reviewed in a team session with final checks before proceeding first with the tow and second with initial startup of LNG operations. A number of action items would generally be identified in such sessions; some would require closure before proceeding to the next step, and others would be identified for action by specific deadlines or milestones. This process and any findings would be formally documented.

AM PS-1b. **Class Certification and a Safety Management Certificate for the FSRU.** Class certification and a safety management certificate are required under international agreements, i.e., through the IMO, for vessels engaged in international voyages. Although this would not be required for the stationary FSRU, the Applicant would obtain class and safety management certification for the facility, including the subsea pipelines, pipeline ending manifest, and risers. The Applicant would voluntarily provide a documented management system that would be in compliance with the International Safety Management Code and the Applicant's internal health, safety, engineering, and construction standards. When operational, the FSRU would be certifiable under the International Safety Management, International Organization for Standardization (ISO) ISO-9000 quality standards and ISO-14000 environmental standards.

AM PS-1c. **Periodic Inspections and Surveys by Classification Societies.** The Applicant would conduct periodic inspections of the FSRU by classification societies, including annual inspections and a full survey after five years of facility operation and every five years thereafter. This would help ensure that shipboard procedures are regularly reviewed and updated and that processing and emergency equipment would be maintained appropriately and repaired or upgraded as necessary.

AM PS-1d. **Designated Safety (Exclusion) Zone and Area to be Avoided.** The Applicant would monitor a 1,640-foot (500 m) radius safety zone to be designated by the USCG around the FSRU where public maritime traffic would be excluded. The Applicant has also proposed designating an Area to be Avoided with a radius of 2 NM (2.3 miles or 3.7 km) around the FSRU. Each of these zones would be marked on nautical charts and would serve as part of the Notice to Mariners to avoid this area.

AM MT-3a. **Patrol Safety Zone** would apply to this impact (see Section 4.3, “Marine Traffic”).

AM MT-3d. **Control Room Team Management Techniques** would apply to this impact (see Section 4.3, “Marine Traffic”).

AM MT-3e. **Broadcast of Navigational Warnings** would apply to this impact (see Section 4.3, “Marine Traffic”).

AM PS-1a would reduce the likelihood and severity of releases by implementing a specific, tested project design and execution process that uses qualified people, is based on site specific information, emphasizes safety, uses analytical tools that identify and quantify potential hazards so that they may be addressed, confirms the design in a model test basin, uses third parties for verification, and conducts a pre-startup review. AM PS-1b would similarly reduce releases by specifying the type of international safety management standards that would be met, and AM PS-1c would provide for verification by an outside expert organization. AM PS-1d would reduce the likelihood and severity of potential vessel accidents near or within the FSRU by limiting access to the area.

AM MT-3a would reduce the likelihood of releases resulting from collisions and intentional actions by warning approaching vessels and also would help to control vessels should an incident occur. AM MT-3d would maximize the effectiveness of crew safety and communications training thereby reducing the potential for dangerous situations to arise. AM MT-3e would increase awareness for local mariners of LNG transfer operations at the FSRU, which may reduce the number of vessels transiting the surrounding area.

<u>Mitigation Measures for Impact PS-1: Operational or Natural Phenomena LNG Release Incident at the FSRU</u>

MM PS-1e. **Cargo Tank Fire Survivability.** The Applicant shall provide safety engineering, HAZIDs, HAZOPs, and QRA supporting the detailed engineering design, including cases where cargo tank insulation is presumed to fail in the event of a fire.

MM PS-1f. **Structural Component Exposure to Temperature Extremes.** The Applicant shall provide safety engineering, HAZIDs, HAZOPs, and QRA supporting the detailed engineering design, including cases where decking, hulls, and structural members are exposed to both cryogenic temperatures from spilled LNG and exposure to extreme heat from a fire, e.g., the Moss storage tanks would be designed with a steel outer shell to provide a barrier against excessive heat and fire in the event of an emergency in the regasification area, and to minimize impacts to multiple tanks.

MM PS-1g. **Pre- and Post-Operational HAZOPs.** The Applicant shall conduct HAZOPs that address all LNG operations prior to beginning operation and after one year of operation. The results of these reviews shall be used to improve and refine operations practices and emergency response procedures. After the initial and first post-operational HAZOPs, additional HAZOPs shall be conducted every two years unless there has been a change in equipment or other significant change. The results of these reviews shall be reviewed as part of configuration management when any equipment, operational, or procedural changes have been undertaken that would necessitate conducting an additional HAZOP review for the new configuration. HAZOPs may be conducted by the Applicant or by a qualified third party, including participation by the CSLC.

MM MT-3f. **Live Radar and Visual Watch** would apply to this impact (see Section 4.3, “Marine Traffic”).

MM PS-1e would improve the ability of LNG storage tanks to withstand the effects of a fire and could also potentially limit the extent of damage caused by an incident. MM PS-1f would reduce the likelihood of a major structural failure by requiring consideration of potentially improbable but high consequence events during Project design. MM PS-1g would reduce the likelihood of a potential emergency incident at the FSRU and would improve the crew’s response if such a situation were to occur.

Finally, MM MT-3f would reduce the likelihood of a collision because the crew would have early warning of nearby vessels or aircraft and would assist in managing an incident should one occur.

The impact would be adverse but reduced to a level below its significance criteria with the implementation of the mitigation measures described above.

Impact PS-2. Potential Release of LNG due to High-Energy Marine Collision or Intentional Attack

A high-energy collision of another vessel with the FSRU or an LNG carrier or an intentional attack could cause a rupture of the Moss tank(s) holding LNG, leading to a release of an unignited flammable vapor cloud that could extend beyond the 1,640-foot (500 m) radius safety zone around the FSRU, impact any members of the boating public in the identified potential impact area, and impact boats traveling in the Traffic Separation Scheme (Class I).

Computer modeling indicated that although rare, a high-energy collision with another vessel could potentially cause a rupture of the Moss tanks holding LNG aboard the FSRU or cause damage to an LNG carrier, and that the consequences of this scenario could lead to fatalities or serious injuries to members of the general public. The range of other release scenarios evaluated, including potential releases that might be caused by intentional sabotage or attacks could also potentially result in releases of LNG that would cause impacts beyond the 1,640-foot (500 m) safety zone around the FSRU.

The FSRU mooring would be located about 2 NM (2.3 miles or 3.7 km) from the edge of the Southbound Coastwise Traffic Lane and 5 NM (5.8 miles or 9.3 km) from the Northbound Coastwise Traffic Lane. Mariners use the following resources to determine whether the risk of collision exists: radar tracking, visual examination of a vessel's aspect and lighting, and hailing a vessel. If the captain of an LNG carrier or another approaching vessel were to mistake the FSRU for a vessel rather than a stationary port, the FSRU captain or the LNG carrier captain could take several steps to avoid a collision.

AIS is a technology that the Applicant proposes to use on the FSRU and would be required on the LNG carriers. The AIS sends information, which is displayed on the other ships' radar. This information includes the name of the vessel, its speed, and its course. Use of the AIS would reduce or eliminate the potential that other vessels would mistake the FSRU for a moving vessel. Since the FSRU and the LNG carriers would be equipped with AIS, the risk of potential collisions would be reduced. In addition, the position of the FSRU, the safety zone, and the ATBA, if approved by the USCG, would be placed on navigation charts. Thus, mariners would know the exact location of the FSRU and could take measures to avoid it.

The Applicant has incorporated the following into the Project:

AM PS-2a. **AIS, Radar, and Marine VHF Radiotelephone.** The Applicant would equip the FSRU with an AIS and with real-time radar and marine VHF radiotelephone capabilities.

AM PS-1a. **Applicant Engineering and Project Execution Process.**

AM PS-1b. **Class Certification and a Safety Management Certificate for the FSRU**.

AM PS-1c. **Periodic Inspections and Surveys by Classification Societies**.

AM PS-1d. **Designated Safety (Exclusion) Zone**.

The following Marine Traffic Applicant measures would also apply to this impact (see Section 4.3, "Marine Traffic").

AM MT-3a. **Patrol Safety Zone**.

AM MT-3b. **LNG Carrier Monitoring by the FSRU**.

AM MT-3c. One LNG Carrier in Approach Route.

AM MT-3d. Control Room Team Management Techniques.

AM MT-3e. Broadcast of Navigational Warnings.

AM PS-2a would reduce the likelihood of a ship collision or intentional event by providing multiple communication channels.

AM PS-1a would reduce the likelihood and severity of releases by implementing a specific, tested project design and execution process that uses qualified people, is based on site specific information, emphasizes safety, uses analytical tools that identify and quantify potential hazards so that they may be addressed, confirms the design in a model test basin, uses third parties for verification, and conducts a pre-startup review. AM PS-1b would similarly reduce releases by specifying the type of international safety management standards that would be met, and AM PS-1c would provide for verification by an outside expert organization. AM PS-1d would reduce the likelihood and severity of potential vessel accidents near or within the FSRU by limiting access to the area.

AM MT-3a would reduce the likelihood of releases resulting from collisions and intentional actions by warning approaching vessels. Similarly, monitoring of LNG tankers under AM MT-3b would reduce the likelihood of collisions between the tankers and the FSRU and between LNG tankers and other vessels. AM MT-3c would further reduce the likelihood of potential collisions with or between LNG tankers. AM MT-3d would maximize the effectiveness of crew safety and communications training, thereby reducing the potential for dangerous situations to arise. AM MT-3e would increase awareness for local mariners of LNG transfer operations at the FSRU, which may reduce the number of vessels transiting the surrounding area.

<u>Mitigation Measures for Impact PS-2: High Energy Vessel Collision or Intentional Attack with LNG Release with or without Ignition</u>

MM PS-1e. Cargo Tank Fire Survivability.

MM PS-1f. Structural Component Exposure to Temperature Extremes.

MM PS-1g. Pre- and Post-Operational HAZOPs.

MM MT-3f. Live Radar and Visual Watch (see Section 4.3, “Marine Traffic”).

MM MT-3g. Information for Navigational Charts (see Section 4.3, “Marine Traffic”).

MM MT-3h. Additional Patrol Vessel (see Section 4.3, “Marine Traffic”).

MM PS-1e would improve the ability of LNG storage tank to withstand the effects of a fire and could also potentially limit the extent of damage caused by an incident. MM PS-1f would reduce the likelihood of a major structural failure by requiring consideration of potentially improbable but high consequence events during Project design. MM PS-1g would reduce the likelihood of a potential emergency incident at the FSRU and would improve the crew's response if such a situation were to occur.

MM MT-3f would allow approaching vessels to be able to take measures to avoid the FSRU. MM MT-3g would ensure that the proposed changes to the navigational charts would be done promptly so that the changes could be completed in an expeditious manner and be published. Once published, the safety zone and the ATBA delineations on navigational charts would assist all mariners transiting the Project area to plan accordingly to avoid the safety zone. MM MT-3h would ensure that any vessels that may stray into the safety zone would be intercepted.

The likelihood of potential impacts from high energy marine collisions or intentional attacks would be reduced with implementation of the measures described above; however, hazard and risk evaluations for these types of incidents indicated that the potential consequences could extend beyond the 1,640-foot (500 m) safety (exclusion) zone around the FSRU. The impacts would therefore still be potentially significant, i.e., could cause serious injury or fatality to members of the public, should an incident occur; therefore, this impact remains significant after mitigation.

A summary of public safety impacts and mitigation measures regarding the FSRU and the DWP is provided in Table 4.2-9.

Table 4.2-9 Summary of Public Safety Impacts and Mitigation Measures for the FSRU and the DWP

Impact	Mitigation Measure(s)
Impact PS-1. An incident at the FSRU or LNG carrier due to human error, upsets, or equipment failures, or as a result of natural phenomena (severe wave conditions, high winds, etc.) could cause a release of LNG from the FSRU or an LNG carrier that would have a limited area of effect (Class II).	**AM PS-1a. Applicant Engineering and Project Execution Process. T**he Applicant would undertake—regardless of any less stringent regulatory requirements—the following steps to design, build, and operate the proposed Project: 1. Prior to final Project internal funding, undertake a full Front End Engineering Design (FEED) exercise with a suitably qualified and experienced contractor under the management of an Applicant technical team. This would define the engineering requirements for the complete Project and identify sources for all remaining detailed information and data, to be ready for internal Project sanction and final detailed engineering. 2. Undertake a comprehensive offshore site survey to determine bathymetry, geology, and geotechnical characteristics of the area in and immediately around the locations of each element of the Project. This would require mobilization of specialized marine vessels and crews to perform the acoustic surveying and soil coring for the shallow water horizontal directional boring (HDB) of the pipelines

Table 4.2-9 Summary of Public Safety Impacts and Mitigation Measures for the FSRU and the DWP

Impact	Mitigation Measure(s)
	crossing under the beach to the FSRU mooring in deep water. The survey results would provide additional information for the final detailed design of the HDB, pipelines, cable crossings, pipeline end manifolds, and mooring system anchors. 3. Fully implement the proposed Project under a self-imposed "Safety Case" process for the detailed design of the proposed Project. This would begin with the FEED but could be completed only when the level of the facility definition is in the advanced detailed design phase. This would require a complex series of additional detailed safety checks and balances be put into place, including HAZID, hazard and operability studies (HAZOPs), quantitative risk analyses (QRA), formal safety analyses (FSA), and associated safety engineering exercises such as process plant modeling and analyses. This would be finalized during the detailed design of the FSRU safety systems, the process plant and deck layouts, and the associated systems such as piping and utilities, and the control systems and procedures. Upon startup, the safety case would become a "living tool" for the facility operating team—one that would be updated and reanalyzed as needed based on operational experience—to ensure that the proposed Project meets or exceeds required standards during all phases of operation. 4. Upon internal Project sanction/funding, ensure detailed engineering would be conducted for all components by suitably qualified and experienced contractors under the management of an Applicant technical team and in accordance with demanding technical requirements that would be carefully defined in contractual documents. The selected qualified engineering contractors would likely be different for the contractor designing the hull, regasification topsides, mooring, pipelines, etc. Using this process, the Applicant would ensure that all engineering is executed to meet or exceed the regulatory and Applicant's internal requirements. 5. Commission a series of model tests of the FSRU facility at an experienced and well-established model test basin. More advanced detailed theoretical analyses would be completed first to identify the governing criteria and cases to be modeled in the basin. These

Table 4.2-9 Summary of Public Safety Impacts and Mitigation Measures for the FSRU and the DWP

Impact	Mitigation Measure(s)
	model tests would cover both the survival sea states without an LNG carrier moored alongside and the operational sea states with the carrier moored alongside the FSRU. FSRU motions and mooring system loads would be measured under survival storm conditions to confirm the calculated results. Similarly, relative and absolute motions of and between the FSRU and the berthed carrier would be measured to confirm the operability limits of the berth mooring, fender, and loading arm systems. This would also provide information about FSRU motions for the detailed design of the topsides equipment. 6. The Applicant would require independent third-party verification of detailed engineering, procured equipment, fabrication, construction, and offshore installation and commissioning of all Project components. Where such independent third-party verification would be required by a regulatory agency, or in order to obtain class certification, a single verification process would be conducted to ensure efficiency of this verification. 7. During the construction phases of the proposed Project, both quality and safety audits at major fabrication/ construction sites would be undertaken by the Applicant to ensure quality and safety of the Project components. Actual safety and quality performance during construction would be a contractual obligation for the various contractors selected by the Applicant. 8. Before releasing the FSRU from its inshore commissioning, i.e., before towing to the proposed Project site, and after offshore installation of all components, but before facility startup, the Applicant would conduct a formal pre-startup review. The status of the facility, quality assurance, “outstanding items,” operational preparedness, and compliance with legal and regulatory commitments would be carefully reviewed in a team session with final checks before proceeding first with the tow and second with initial startup of LNG operations. A number of action items would generally be identified in such sessions; some would require closure before proceeding to the next step, and others would be identified for action by specific deadlines or milestones. This process and any findings would be formally documented.

Table 4.2-9 Summary of Public Safety Impacts and Mitigation Measures for the FSRU and the DWP

Impact	Mitigation Measure(s)
	AM PS-1b. Class Certification and a Safety Management Certificate for the FSRU. Class certification and a safety management certificate are required under international agreements, i.e., through the IMO, for vessels engaged in international voyages. Although this would not be required for the stationary FSRU, the Applicant would obtain class and safety management certification for the facility, including the subsea pipelines, pipeline ending manifest, and risers. The Applicant would voluntarily provide a documented management system that would be in compliance with the International Safety Management Code and the Applicant's internal health, safety, engineering, and construction standards. When operational, the FSRU would be certifiable under International Safety Management, International Organization for Standardization (ISO) ISO-9000 quality standards and ISO-14000 environmental standards. **AM PS-1c. Periodic Inspections and Surveys by Classification Societies.** The Applicant would have conducted periodic inspections of the FSRU by classification societies, including annual inspections and a full survey after five years of facility operation and every five years thereafter. This would help ensure that shipboard procedures are regularly reviewed and updated and that processing and emergency equipment would be maintained appropriately and repaired or upgraded as necessary. **AM PS-1d. Designated Safety (Exclusion) Zone and Area to be Avoided.** The Applicant would monitor a 1,640-foot (500 m) radius safety zone to be designated by the USCG around the FSRU where public maritime traffic would be excluded. The Applicant has also proposed designating an Area to be Avoided with a radius of 2 NM (2.3 miles or 3.7 km) around the FSRU. Each of these zones would be marked on nautical charts and would serve as part of the Notice to Mariners to avoid this area. **AM MT-3a. Patrol Safety Zone** (see Section 4.3, "Marine Traffic"). **AM MT-3d. Control Room Team Management Techniques** (see Section 4.3, "Marine Traffic"). **AM MT-3e. Broadcast of Navigational Warnings** (see Section 4.3, "Marine Traffic"). **MM PS-1e. Cargo Tank Fire Survivability.** The Applicant shall provide safety engineering, HAZIDs, HAZOPs, and QRA supporting the detailed

Table 4.2-9 Summary of Public Safety Impacts and Mitigation Measures for the FSRU and the DWP

Impact	Mitigation Measure(s)
	engineering design, including cases where cargo tank insulation is presumed to fail in the event of a fire. **MM PS-1f. Structural Component Exposure to Temperature Extremes.** The Applicant shall provide safety engineering, HAZIDs, HAZOPs, and QRA supporting the detailed engineering design, including cases where decking, hulls, and structural members are exposed to both cryogenic temperatures from spilled LNG and exposure to extreme heat from a fire, e.g., the Moss storage tanks would be designed with a steel outer shell to provide a barrier against excessive heat and fire in the event of an emergency in the regasification area, and to minimize impacts to multiple tanks. **MM PS-1g. Pre- and Post-Operational HAZOPs.** The Applicant shall conduct HAZOPs that address all LNG operations prior to beginning operation and after one year of operation. The results of these reviews shall be used to improve and refine operations practices and emergency response procedures. After the initial and first post-operational HAZOPs, additional HAZOPs shall be conducted every two years unless there has been a change in equipment or other significant change. The results of these reviews shall be reviewed as part of configuration management when any equipment, operational, or procedural changes have been undertaken that would necessitate conducting an additional HAZOP review for the new configuration. HAZOPs may be conducted by the Applicant or by a qualified third party, including participation by the CSLC. **MM MT-3f. Live Radar and Visual Watch** (see Section 4.3, “Marine Traffic”).
Impact PS-2. A high-energy collision with the FSRU or an LNG carrier and another vessel or an intentional attack could cause a rupture of the Moss tanks holding LNG, leading to a release of an unignited flammable vapor cloud that could extend beyond the 1,640-foot (500 m) radius safety zone around the FSRU, or could impact members of the boating public in the vicinity of an LNG carrier (Class I).	**AM PS-2a. AIS, Radar, and Marine VHF Radiotelephone.** The Applicant would equip the FSRU with AIS and with real-time radar and marine VHF radiotelephone capabilities. **AM PS-1a. Applicant Engineering and Project Execution Process.** **AM PS-1b. Class Certification and a Safety Management Certificate for the FSRU**. **AM PS-1c. Periodic Inspections and Surveys by Classification Societies.** **AM PS-1d. Designated Safety (Exclusion) Zone.** **AM MT-3a. Patrol Safety Zone** (see Section 4.3, “Marine Traffic”). **AM MT-3b. LNG Carrier Monitoring by the FSRU** (see Section 4.3, “Marine Traffic”). **AM MT-3c. One LNG Carrier in Approach Route**

Table 4.2-9 Summary of Public Safety Impacts and Mitigation Measures for the FSRU and the DWP

Impact	Mitigation Measure(s)
	(see Section 4.3, "Marine Traffic"). **AM MT-3d. Control Room Team Management Techniques** (see Section 4.3, "Marine Traffic") **AM MT-3e. Broadcast of Navigational Warnings** (see Section 4.3, "Marine Traffic") **MM PS-1e. Cargo Tank Fire Survivability.** The Applicant shall include LNG cargo tank fire survivability after loss of insulation in engineering design analyses. **MM PS-1f. Structural Component Exposure to Temperature Extremes.** **MM PS-1g. Pre- and Post-Operational HAZOPs.** **MM MT-3f. Live Radar and Visual Watch** (see Section 4.3, "Marine Traffic"). **MM MT-3g. Information for Navigational Charts** (see Section 4.3, "Marine Traffic"). **MM MT-3h. Additional Patrol Vessel** (see Section 4.3, "Marine Traffic").

4.2.8 Natural Gas Pipelines

4.2.8.1 Background

Natural Gas Properties and Hazards

Natural gas consists principally of methane, along with smaller amounts of heavier hydrocarbons including ethane, propane, and butane. The acceptable ranges for gas composition, including the hydrocarbon content, nonhydrocarbon gases, and contaminants for natural gas used in California, are set through CPUC-approved tariff agreements between the Applicant and the public utility accepting the gas for distribution to its service area. The primary component of natural gas, methane, is colorless, odorless, and tasteless. It is not toxic but is classified as an asphyxiant, posing a slight inhalation hazard. Oxygen deficiency can occur if methane is inhaled in high concentration, resulting in serious injury or death. For this reason, pipeline safety regulations contained in 49 CFR Part 192.625 require that an odorant be added to natural gas. See Chapter 2, "Description of the Proposed Action," for discussion of odorization to the natural gas pipeline.

Methane has an auto-ignition temperature (the minimum temperature required in the absence of a spark or flame to set methane on fire) of 1,166 °F (630 °C) and is flammable at concentrations between 15 percent (15 percent methane, 85 percent air) and 5 percent (5 percent methane, 95 percent air) by volume. Flammable concentrations of methane within an enclosed space in the presence of an ignition source can explode. However, because the specific gravity of methane in air is 0.55, which means that methane is buoyant at atmospheric pressures and temperatures and disperses rapidly in air unconfined mixtures of methane in air are rarely explosive.

Historical Natural Gas Pipeline Incident Data

A substantial amount of historical data exists regarding the hazards and risks associated with pipeline transportation of natural gas. For decades, pipeline operators have been required to provide specific information regarding pipeline incidents to the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA) Office of Pipeline Safety (OPS). The CPUC also addresses risk management as part of its regulatory jurisdiction over 100,000 miles (161,000 km) of utility-owned intrastate natural gas pipelines, which transported 85 percent of the total amount of natural gas delivered to California's gas consumers in 2003.

In this document, historical pipeline data is drawn only from pipeline operations in the U.S., which are subject to the same regulatory requirements and agency oversight for design, inspection, maintenance, and operations as would be applied to the new pipelines to be constructed as part of the proposed Project. Data from numerous serious incidents involving natural gas transmission pipelines around the world are not included in the evaluation for the proposed Project because of substantial differences in the way the pipelines are operated from those in the U.S.

Table 4.2-10 presents a summary of natural gas transmission pipeline incident data for three periods: 1970 to 1984 (under the old reporting requirements); the 1990s (under newer reporting requirements); and 2000 to 2003. The data include onshore and offshore pipelines. Incident causes fall into three main categories: outside forces, corrosion, and defects in construction or materials. A fourth category includes reports where the cause was not specified or was attributable to a less common cause. Data are not yet available under the most recent reporting changes for natural gas transmission pipelines.

The dramatic decrease in the total number of reportable incidents since 1990, as compared to the period of 1970 through 1984, is illustrated in the last row of Table 4.2-10, which shows the total number of incidents and the annual average number of incidents each year for the period reported. Although part of the decrease was due to the 1984 change in reporting requirements, the decrease is also the result of implementing a number of pipeline safety initiatives over the past few decades, which have significantly reduced the number of incidents attributable to outside forces, likely due to better pipeline signage and more universal use of one-call notification systems before excavation. As older pipelines have been abandoned or upgraded to include cathodic protection systems, the number of incidents associated with corrosion events has also decreased.

Table 4.2-10 Natural Gas Transmission Pipeline Incidents by Cause

Cause	1970 to 1984	1990-1999	2000-2003
Outside Forces – Total	**54%**	**41.1%**	**32.8%**
Car, Truck or Other Vehicle not related to Excavation Activity	36%		3.19%
Third-Party Excavation Damage			8.12%
Operator Excavation Damage	3.9%		1.16%
Earth Movement	7.2%		1.16%
Weather: Lightning, Heavy Rains/Floods, High Winds	5.8%		2.32%
Other, Vandalism	0.81%		0.58%
Outside Forces			16.23%
Corrosion – Total	**17%**	**22.3%**	**27.0%**
Corrosion, External		8.62%	11.30%
Corrosion, Internal		13.5%	15.36%
Corrosion, Not Specified		0.13%	0.29%
Construction or Material Defect – Total	**21%**	**15.3%**	**17.7%**
Body of Pipe			2.03%
Component			1.45%
Construction or Material Defect			5.51%
Butt Weld			1.74%
Fillet Weld			0.58%
Joint			1.74%
Pipe Seam Weld			2.90%
Ruptured or Leaking Seal/Pump Packing			0.29%
Threads Stripped, Broken Pipe Coupling			1.45%
Other – Total	**8%**	**21.4%**	**22.6%**
Fire/Explosion as Primary Cause			0.29%
Incorrect Operation			1.45%
Malfunction of Control/Relief Equipment			1.16%
Miscellaneous			3.77%
Other			12.75%
Rupture of Previously Damaged Pipe			0.29%
Unknown			2.90%
Total Incidents and Annual Average	**Total: 5,862 Average: 404/yr**	**Total: 771 Average: 77/yr**	**Total: 345 Average: 86/yr**

A significant increase in gas leaks in small natural gas distribution lines operated by Washington Gas Light in an area of Prince George County, Maryland, was determined to be caused by the composition of regasified LNG imported through the Dominion Cove Point terminal in Calvert County, Maryland. The investigation of the natural gas leaks at the Washington Gas Light attributed the increase in the number of leaks to the following factors:

- Aging Seals. The seals used in the Washington Gas Light network had been in place for 30 to 50 years. Some of them had decreased sealing force;
- Change in Gas Composition. Some sealing material shrank due to change in gas composition; and
- Temperature Decrease. With the onset of winter, the sealing shrank additionally as the ground temperature cooled.

According to testimony provided Kevin Shea of San Diego Gas and Electric and SoCalGas before the CPUC, neither San Diego Gas and Electric nor SoCalGas have experienced these types of problems with its interstate or intrastate gas pipelines. Each organization is investigating whether it has used the couplings that have experienced the problems and whether they should remain in use. Mr. Shea also pointed out that one key difference is that California does not experience the drops in ground temperatures that occur on the East Coast. San Diego Gas and Electric and SoCalGas thoroughly analyze all new pipeline components introduced into the system to evaluate their compatibility with the anticipated gas composition (Shea 2005).

Factors Affecting Pipeline Incident Frequencies

The incident frequency that may be expected for a specific segment of pipeline varies widely in terms of age, pipe diameter, and level of corrosion control.

The dominant incident cause over the decades has been from outside forces, constituting 53.5 (54) percent of all service incidents between 1970 and 1984. This was also the case for incidents reported during the 1990s and during the 2000 to 2003 time frame. Outside force incidents include the encroachment of mechanical equipment such as bulldozers and backhoes, or from dragging boat anchors or trawling equipment; from earth movement due to soil settlement, washouts, or seismic hazards; from weather effects such as winds, storms, and thermal strains; and from willful damage.

Older pipelines also have a higher frequency of outside forces incidents, partly because their location may be less well known and less well marked than newer lines. In addition, the older pipelines contain a disproportionate number of smaller-diameter pipelines, which have a greater rate of outside force incidents. Small-diameter pipelines are more easily crushed or broken by mechanical equipment or earth movement.

The frequency of service incidents is strongly dependent on pipeline age. While pipelines installed since 1950 exhibit a fairly constant level of service incident frequency, pipelines installed before that time have a significantly higher rate, particularly due to corrosion. More technologically advanced coatings and cathodic protection to reduce corrosion potential are generally used on newer pipelines.

Southern California Gas Company – Reportable Natural Gas Releases

Pipeline operators that experience reportable incidents involving natural gas pipelines must report these to the National Response Center (NRC). A database query for incident reports filed by SoCalGas identified a total of 29 incidents where natural gas had been released from a SoCalGas pipeline (NRC 2004). A number of these incidents occurred as a result of third-party damage to distribution lines, but the remaining incidents involved transmission pipelines. These are summarized in Table 4.2-11. While additional incidents may have been reported to the CPUC, which has more stringent reporting requirements, this information is confidential and cannot be publicly disseminated.

Table 4.2-11 SoCalGas Natural Gas Transmission Pipeline Incidents Reported to the National Response Center

Incident Report No./ Date	Location/ Cause/Description	Damages
781854 / April 26, 2005	Intersection of Nebraska and Academy, Selma, Fresno County. Release from gas meter caused by motor vehicle accident.	1 injury with hospitalization. No damages, fatalities, or evacuations noted at time of report.
776676 / October 19, 2005	9753 Rancho Rd., Adelanto, San Bernardino County. Release from 30-inch steel pipeline during pigging operation caused by operator error.	No injuries, fatalities, evacuations, or damages noted at time of report.
760644 / June 1, 2005	Flamingo Rd. at Bluebird Canyon Dr., Laguna Beach, Orange County. Gas line break resulting from large landslide.	> $50,000 in damages. No injuries, fatalities, or evacuation noted at time of report.
746942 / January 11, 2005	Old Waterman Canyon Rd., San Bernardino, San Bernardino County. Release from 4-inch pipeline resulting from storm-related landslide.	No injuries, fatalities, evacuations, or damages noted at time of report.
746361 / December 9, 2004	Highway 166 at Old River Rd., Taft, Kern County. 12-inch high-pressure line struck by farming equipment.	No injuries, fatalities, evacuations, or damages noted at time of report.
746359 / October 1, 2004	Old River Rd., Mettler, Kern County. 12-inch high-pressure line struck by farming equipment.	No injuries, fatalities, evacuations, or damages noted at time of report.

Table 4.2-11 SoCalGas Natural Gas Transmission Pipeline Incidents Reported to the National Response Center

Incident Report No./ Date	Location/ Cause/Description	Damages
May 5, 2004	Ventura County, Rose Avenue in El Rio. The impact of a vehicle collision pushed a passenger van off the roadway and onto a small natural gas line regulator station, snapping off the pressure valve.	Approximately 700,000 ft^3 (19,800 m^3) of natural gas released, roadways within 8 square miles (20.7 km^2) blocked to traffic, and staff/students at nearby Rio Mesa High School directed to shelter in place. Valve was reportedly replaced within an hour, and no serious injuries were reported. Incident involved distribution line and did not meet minimum criteria to require reporting to the NRC. Incident did meet CPUC reporting criteria and was reported to CPUC by SoCalGas.
703085 / October 20, 2003	Intersection of Bushard and Hazard, Garden Grove, Orange County. Damage to steel gas line, cause unreported.	1 injury noted in report, no hospitalization. No damages, fatalities, or evacuation noted at time of report.
641136 / April 2, 2003	8141 Gulana Ave., Playa Del Ray, Los Angeles County. Release of gas to atmosphere from valve because of shutdown of ESD system.	> $75,000 in damages. No injuries, fatalities, or evacuation noted at time of report.
630656 / December 2, 2002	Intersection of Rustic Glenn and Harveston Dr., Temecula, Riverside County. 2-inch plastic main damaged by third party while performing maintenance work.	2 injuries, both hospitalized. No damages, fatalities, or evacuations noted at time of report.
595360 / March 1, 2002	1317 Palisades Beach Rd., Santa Monica, Los Angeles County. 1.25-inch service line cut by a third party using a concrete saw.	No damages, injuries, or fatalities noted at time of report. 12 people evacuated.
591361 / January 16, 2002	Kern County, Valley Acres, in the right-of-way 0.25 mile (0.4 km) south of State Route 119. 26–inch (0.7 m) transmission line break due to unknown causes, estimated release duration 2 hours.	$50,000 in damages. No injuries or fatalities noted. Evacuated 24 private citizens. Closed State Route 119, both north and south.
589269 / December 21, 2001	16468 Lakeshore Dr., Elsinore, Riverside County. Distribution mail leaked – cause unknown but believed to be damage by third party. Explosion reported.	> $2,500,000 in damages. No injuries, fatalities, or evacuation noted at time of report.

Table 4.2-11 SoCalGas Natural Gas Transmission Pipeline Incidents Reported to the National Response Center

Incident Report No./ Date	Location/ Cause/Description	Damages
565500 / May 9, 2001	Los Angeles County, Santa Clarita, 26623 May Way. Odor complaint due to purging a high-pressure gas transmission line. Estimated 2-hour release.	12 injuries noted in report. No hospitalizations, fatalities, or evacuation noted.
555595 / February 2, 2001	Santa Barbara County, Cuyuma, 5 miles (8 km) from city, 0.5 mile (0.8 km) west of State Route 133, and 2.5 mile (4 km) south of State Route 166. Third-party excavation ruptured underground transmission line.	$80,000 in damages, No injuries, fatalities, or evacuation noted at time of report.
521504 / February 29, 2000	1005 East Third St., Calexico, Imperial County. Service line damaged by backhoe operator; released gas ignited, damaging one home.	> $75,000 in damages. No injuries, fatalities, or evacuation noted at time of report.
503224 / October 21, 1999	3996 Frandon Court, Simi, Ventura County. Leak in 0.5-inch (1.3-centimeter [cm]) line at residence resulted in explosion and fire.	> $50,000 in damages. No injuries, fatalities, or evacuation noted at time of report.
468762 / December 24, 1998	Kern County, 8 miles (12.9 km) south of Lost Hills. “Transfer” pipeline failed due to “earth movement.” Release was secured.	None noted in report.
467562 / December 14, 1998	5300 Machado Rd., Culver City, Los Angeles County. 2-inch (0.05 m) pipeline ruptured by backhoe while digging trench at construction site.	No injuries, fatalities, evacuations, or damages noted at time of report.
466649 / December 4, 1998	Intersection of Lincoln and Walker Aves., Cyprus, Orange County. 8-inch (0.2 m) steel gas main damaged by third party contractor while trenching.	> $50,000 in damages. No injuries, fatalities, or evacuation noted at time of report.
461704 / October 28, 1998	Riverside, State Route 91 at Arlington Avenue. 30-inch (0.76 m) transmission line, 2-inch (5 cm) fitting ruptured by contractor. Release was adjacent to railroad line.	Rail traffic through area stopped.
455537 / September 15, 1998	Balboa Blvd. & 37th St., Newport Beach, Orange County. Corrosion in 6-inch (0.15 m) steel distribution line.	> $50,000 in damages. No injuries, fatalities, or evacuation noted at time of report.

Table 4.2-11 SoCalGas Natural Gas Transmission Pipeline Incidents Reported to the National Response Center

Incident Report No./ Date	Location/ Cause/Description	Damages
453794 / September 3, 1998	5317 Trail St., Norco, Riverside County. Brittle cracking in 4-inch (0.1 m) plastic underground service line.	One injury. No fatalities, no evacuation, and no damages noted at time of report.
426636 / March 2, 1998	Ventura County, Somis, 4149 Clubhouse Drive. 24-inch (0.6 m) transmission line break due to landslide.	> $50,000 in damages, No injuries, fatalities, or evacuation noted at time of report.
426474 / March 1, 1998	Los Angeles County, Santa Clarita, Saticoy. 20-inch (0.5 m) transmission line break due to landslide.	> $50,000 in damages, No injuries, fatalities, or evacuation noted at time of report.
366376 / October 26, 1996	Los Angeles County, Sylmar, Foothill and Balboa Streets Expansion joint ruptured on transmission line ruptured.	> $50,000 in damages, No injuries, fatalities, or evacuation noted at time of report.
287958 / April 19, 1995	Ventura County, La Conchita, Line 1003 16-inch (0.4 m) transmission line break due to landslide. Line isolated.	> $50,000 in damages, No injuries, fatalities, or evacuation noted at time of report.
217077 / January 17, 1994	Los Angeles County Earthquake. Unknown quantity released. Preliminary information on service status: 1,200 service outages, 3 transmission lines, and 25 distribution lines out of service.	Unknown at the time of the report.

Estimated Pipeline Safety Risks

For the purposes of this analysis, risks associated with the pipeline transportation of natural gas have been estimated based on historical pipeline incident data compiled by the Federal OPS. These data provide a sound basis for a quantitative estimate of the potential risks—the nature of the hazard, the potential consequences, and the probability of occurrence or frequency—based on reports collected over several decades from operation of hundreds of thousands of pipeline miles. These data are analyzed and used to develop new pipeline safety regulations, such as conducting more frequent inspections by agency staff or even criminal enforcement actions against the operator. The OPS also evaluates safety-related condition and incident reports to identify trends or common causes of pipeline incidents that may be concerns for all pipeline operators and issues advisory bulletins to pipeline operators when such concerns are identified. These notices are also published in the Federal Register.

OPS data include both onshore and offshore pipeline incidents and do not distinguish between the two. Since February 9, 1970, all operators of natural gas transmission and gathering systems have been required to notify the OPS of any reportable incident and to submit a written report describing the incident.

The service incidents summarized above in Table 4.2-10 above include pipeline failures of all magnitudes with widely varying consequences, and pipelines of all ages and diameters. About two-thirds of the incidents were classified as leaks; the remaining one-third were classified as ruptures, implying a more serious failure.

The SoCalGas-reported natural gas pipeline incidents shown in Table 4.2-11 provide a general idea of the nature, frequency, and consequences of accidents that have been experienced by this pipeline operator.

The NRC Committee on the Safety of Marine Pipelines reviewed the causes of past pipeline failures, the potential for future failures, and the means of preventing or mitigating these failures and determined that the marine pipeline network does not present an extraordinary threat to human life. Table 4.2-12 presents the annual summaries of reported incidents associated with onshore and offshore natural gas transmission and gathering pipelines from 1986 to 2005. During this 20-year period, the data indicate that efforts to improve pipeline safety had some success: although higher numbers of incidents have occurred in recent years, there is an overall decreasing trend in the numbers of fatalities and injuries. This is illustrated in the trend lines shown in Figure 4.2-2. The recent upward trend in the total number of incidents is reflected in the breakdown by cause. For example, in 2004, 42 of the 121 incidents (35 percent) were caused by outside forces including: non-construction related vehicle accidents; damage caused by a third party, e.g., construction contractors using a backhoe; earth movement; heavy rains and flooding; and fires/explosions. In 2005, 75 of the 160 incidents (47 percent) were caused by these same non-operational outside forces.

The data show that the annual average for the period 1986 through December 3, 2005, was 3.2 fatalities per year during the operation of about 324,600 miles (522,280 km) of onshore and offshore natural gas transmission and gathering pipelines. The data is not categorized by onshore versus offshore pipelines. Pipeline accidents involving deaths or injuries were described as rare (68 FR 69369, December 12, 2003). Using combined incident data for onshore and offshore pipelines represents a conservative approach for estimating the potential risks to the public from the twin subsea pipelines associated with the Project.

The historical data shown in Table 4.2-12 include incidents for older pipelines that were not subject to the more stringent design and safety criteria applied to new pipeline construction and a wide variety of pipeline sizes and types.

The nationwide totals of accidental fatalities from various human-caused and natural hazards as listed in Table 4.2-13 provide a relative measure of the industry-wide safety of natural gas pipelines. Direct comparisons between accident categories should be made cautiously because individual exposures to hazards are not uniform among categories. As shown in Table 4.2-13, the potential impact to the public from the operation of natural gas transmission pipelines in the U.S. is considerably less than for other types of transportation. In addition, the table illustrates the difference in the safety record for gas transmission pipelines compared to gas distribution pipelines, which tend to be smaller in diameter, have thinner wall thicknesses, may be constructed of plastic pipe rather than steel, and are often not as well marked as transmission system piping.

Table 4.2-12 Annual Incident Summaries – U.S. Gas Transmission Pipelines[a]

Year	Incidents	Fatalities [b]	Injuries [b]	Property Damage	Total Transmission and Gathering Pipelines (miles/km)
1986	83	6	20	$11,166,262	321,653 (517, 650)
1987	70	0	15	$4,720,466	323,988 (521,410)
1988	89	2	11	$9,316,078	320,202 (515,315)
1989	103	22	28	$20,458,939	320,070 (515,102)
1990	89	0	17	$11,302,316	324,410 (522,087)
1991	71	0	12	$11,931,238	326,575 (525,571)
1992	74	3	15	$24,578,165	324,097 (521,584)
1993	95	1	17	$23,035,268	325,319 (523,550)
1994	81	0	22	$45,170,293	332,849 (519,575)
1995	64	2	10	$9,957,750	327,866 (527,649)
1996	77	1	5	$13,078,474	321,791 (517,872)
1997	73	1	5	$12,078,117	328,821 (529,096)
1998	99	1	11	$44,487,310	331,867 (534,080)
1999	54	2	8	$17,695,937	328,378 (525,096)
2000	80	15 [c]	18	$17,868,261	326,506 (528,658)
2001	87	2	5	$23,674,225	312,654 (502,228)
2002	82	1	5	$26,552,569	324,767 (525,518)
2003	99	1	8	$47,106,213	320,366 (511,099)
2004	121	1	3	$67,697,511	325,235 (523,303)
2005[d]	160	3	7	$213,532,766	not available
Totals 1986- 2005	**1,751**	**64**	**242**	**$655,408,158**	**---**
Average Annually 1986- 2005	**87.5**	**3.2**	**12.1**	**$32,770,408**	**324,600 (522,281)**

Notes:

[a]1986 through 2005, USDOT Office of Pipeline Safety, Gas Pipeline Statistics, accessed 12/19/2005 at http://ops.dot.gov/stats/stats.htm and http://ops.dot.gov/stats/GTANNUAL2.HTM

[b]Injury and fatality data reported are for transmission and gathering lines, and include workers as well as members of the public.

[c]This includes 12 people killed in the El Paso Natural Gas pipeline incident near Carlsbad, New Mexico.

[d]Through December 3, 2005.

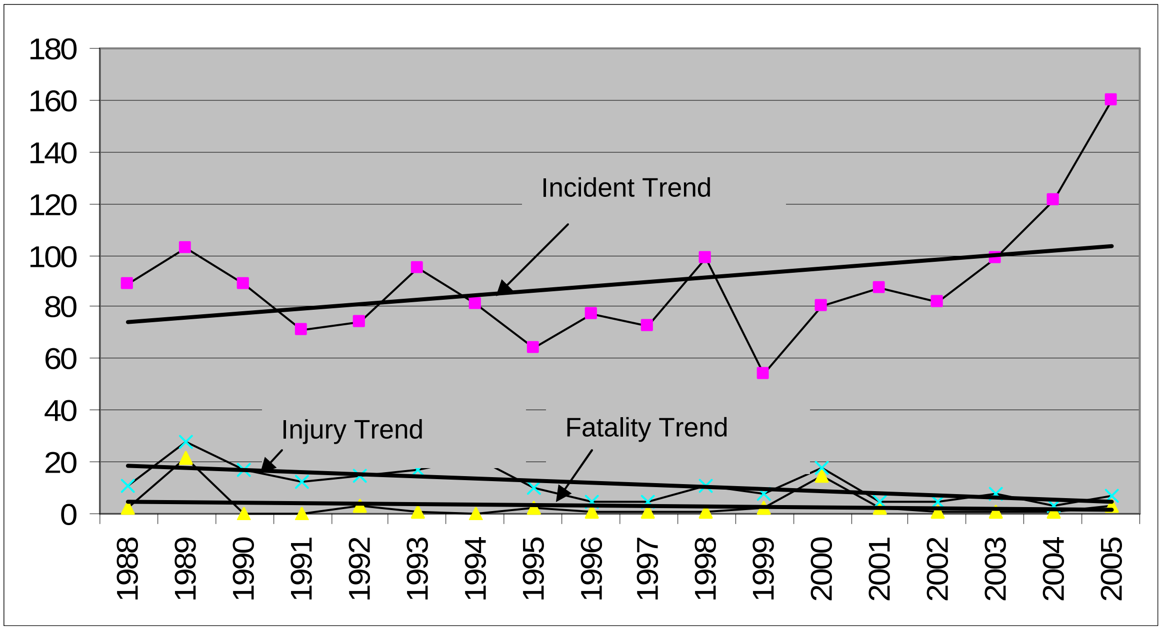

Figure 4.2-2 Pipeline Incident, Injury, and Fatality Trends 1986–2005

Table 4.2-13 Annual Transportation Accidental Deaths

Type of Accident	Average Number of Fatalities per Year[a]	Most Recent Year Fatalities (2002/2003)
All transportation accidents and adverse effects (1990, 1995, 1997, 1998 average)[a]	93,525[a]	44,888[c]
Motor vehicles (1990, 1994-1998 average)[a]	42,114[a]	42,643[c]
Motor vehicle traffic collisions in California (2003)	---	4,225[d]
Railroad accidents (1990-1998 average)[a]	1,158[a]	767[c]
Aviation accidents	---	707[c]
Marine accidents	---	759[c]
Gas distribution pipelines (1990-2005 average)[b]	15.4[b]	10 [b]
Gas transmission pipelines (1986–2005 average)[b]	3.2[b]	3[b]

Notes:

[a]All data, unless otherwise noted, reflect statistics from the U.S. Department of Commerce, Bureau of the Census, Statistical Abstract of the United States, 118th Edition (1998)

[b]U.S. Department of Transportation, Office of Pipeline Safety. 2005 http://ops.dot.gov/stats.html

[c]National Gas Institute's Daily Gas Price Index. September 7, 2004. "NTSB Reports Gas Pipeline Fatalities Up Slightly in 2003." Note that the increase was due to distribution line incidents, not transmission line accidents.

[d]California Department of Finance, Number of Motor Vehicle Traffic Collisions and Persons Killed and Injured. 2002. http://www.dof.ca.gov/html/fs_data/stat-abs/tables/j8.xls

4.2.8.2 Regulations Regarding Pipelines

Table 4.2-14 identifies major laws, regulatory requirements, and plans for pipeline safety. Applicable regulations are further described in Appendix C3 under “Design and Safety Standards Applicable to Natural Gas Transmission Pipelines.” The U.S. Department of Transportation (DOT) pipeline standards are published in 49 CFR Parts 190-199. The standards do not address other issues such as siting and routing, bond issues, which are a matter of private negotiation between pipeline companies and landowners and/or local government zoning boards.

Table 4.2-14 Major Laws, Regulatory Requirements, and Plans for Public Safety Regarding Pipelines

Law/Regulation/Plan/ Agency	Key Elements and Thresholds; Applicable Permits
Federal	
49 CFR Parts 173 and 177 *- PHMSA OPS*	• Regulates transportation of hazardous materials in portable tanks and by highway. • Specifies minimum requirements for portable tanks and cargo tank motor vehicles. • Specifies requirements for driver training, inspections, shipping papers, segregation of hazardous materials, • Requires engine shutoff and bonding and grounding between containers to prevent accidental ignition due to static electricity for Class 3 materials (flammable and combustible liquids).
Pipeline Safety Act of 1994 49 U.S.C. § 60101 et seq. *PHMSA OPS*	• Defines the framework for pipeline safety regulation in the U.S.
Pipeline Safety Improvement Act of 2002, P.L. 107-355, 49 U.S.C. § 60101 et seq. *- PHMSA OPS, CSLC, CPUC*[a]	• Tightens Federal inspection and safety requirements to include mandatory inspections of oil and natural gas pipelines with a history of safety problems within the next five years, with all pipelines to be inspected within ten years. All pipelines will then be inspected at seven-year intervals. • States that PHMSA OPS can order corrective actions, including physical inspection, testing, repair or replacement.. • Requires development and implementation of pipeline integrity management programs by pipeline operators, including identifying areas where risks may be greater due to the population density (High Consequence Areas) and implementing a series of actions to mitigate the potential hazards in these areas. • Emphasizes the one-call notification system and encourages pipeline operators to voluntarily adopt and implement best practices for notification of leaks and ruptures. • Requires the establishment of public education programs by pipeline operators to provide municipalities, schools, and other entities with information to prevent pipeline damage and to prepare for any pipeline emergencies, including the one-call notification system, possible hazards from accidental releases from a pipeline, and actions to take in the event of a release.

Table 4.2-14 Major Laws, Regulatory Requirements, and Plans for Public Safety Regarding Pipelines

Law/Regulation/Plan/ Agency	Key Elements and Thresholds; Applicable Permits
	• Defines coordinated environmental review and permitting process to expedite conducting any necessary pipeline repairs. • Assesses maximum civil penalties against pipeline operators for violations of pipeline safety standards have increased. • Significantly strengthens the enforcement of pipeline safety laws and includes specific whistleblower protections for employees who provide information to the Federal government about pipeline safety. • Mandates continued Federal pipeline safety research and development by the National Institute of Standards and Technology, Department of Transportation, and Department of Energy.
49 CFR Part 190 *- PHMSA OPS*	• Describes availability of informal guidance and interpretive assistance for pipeline safety programs and procedures and establishes framework for inspections and for safety enforcement actions.
49 CFR Part 191 *- PHMSA OPS, CSLC, CPUC*[a]	• Sets requirements for annual reports, incident reports, and safety-related condition reports.
49 CFR Part 192 *- PHMSA OPS, CSLC, CPUC*[a]	• Sets minimum Federal safety standards for transportation of natural gas and other gases, including minimum materials properties such as yield strength; design formulas; standards for valves, flanges, fittings, supports and anchors; pipeline pressure controls; welding requirements; installation designs and limitations; corrosion control and monitoring; testing and inspection requirements; remedial and repair measures; environmental protection and safety requirements; procedural manuals for operations, maintenance, and emergencies; damage prevention programs; incident investigation; gas odorization; and requirements for abandonment or deactivation of facilities. • Each pipeline operator must establish an emergency plan that includes procedures for minimizing the hazards in a natural gas pipeline emergency. Key elements of the plan include procedures for: - Receiving, identifying, and classifying emergency events, gas leaks, fires, explosions, and natural disasters; - Establishing and maintaining communications with local fire, police, and public officials, as well as coordinating emergency response; - Making personnel, equipment, tools, and materials available at the scene of an emergency; - Protecting people first and then property and making them safe from actual or potential hazards; and - Implementing emergency shutdown of the system and safely restoring service. • Requires each operator to establish and maintain a liaison with the appropriate fire, police, and public officials to learn the resources and responsibilities of each organization that may respond to a natural gas pipeline emergency and to coordinate mutual assistance. • Subpart O describes Pipeline Integrity Management Programs for High Consequence Areas. Continuing public education programs must convey information about:

Table 4.2-14 Major Laws, Regulatory Requirements, and Plans for Public Safety Regarding Pipelines

Law/Regulation/Plan/ Agency	Key Elements and Thresholds; Applicable Permits
	- The use of a one-call notification system prior to excavation, and other damage prevention activities; - The possible hazards associated with unintended releases from the pipeline facility; - The physical indications that such a release may have occurred; - What steps should be taken for public safety in the event of a pipeline release; and - How to report such an event. • The Final Rule on Operator Public Awareness Programs (May 2005) states under 192.616: (d) The operator's [public awareness] program must specifically include provisions to educate the public, appropriate government organizations, and persons engaged in excavation-related activities. (e) The program must include activities to advise affected municipalities, school districts, businesses, and residents of pipeline facility locations. (f) The program and the media used must be as comprehensive as necessary to reach all areas in which the operator transports gas. (g) The program must be conducted in English and in other languages commonly understood by a significant number and concentration of the non-English speaking population in the operator's area.
49 CFR Part 199 *- PHMSA OPS, CSLC, CPUC*[a]	• Requires drug and alcohol testing for pipeline operators.
State	
CPUC General Order 112-E State of California Rules Governing Design, Construction, Testing, Operation, and Maintenance of Gas Gathering, Transmission, and Distribution Piping Systems (CPUC 1996) *- CPUC*	• More stringent than USDOT requirements. • Rule 30 "Transportation of Customer-Owned Gas," limits specific concentrations for a number of substances, including hydrogen sulfide, mercaptan, sulfur, and hazardous substances.
Local	
South Coast Air Quality Management District	• Issues specific rules for the sulfur content of natural gas.
Ventura County Air Pollution Control District	• Issues specific rules for the sulfur content of natural gas.

[a]The USDOT, through PHMSA OPS, has statutory authority for pipeline safety in the U.S. but has delegated that authority for intrastate utility-owned natural gas pipelines to the CPUC.

The Applicant would design, install, operate, maintain, and inspect pipelines to meet regulatory requirements, which include automatic monitoring of pipeline pressure and other conditions using a SCADA system and routine internal pipeline inspections (including smart pigs). This would reduce the chances for potential deterioration or incidental damage to the pipeline to go undetected and unrepaired. As another example, the Applicant would ensure that pipelines laid on the seafloor in shallower waters would be weight-coated with concrete or equivalent material to provide additional pipeline mass, which would provide additional protection to the pipeline from fishing gear and would design and install pipelines to meet seismic criteria to ensure that pipeline integrity is maintained during severe seismic events that might be expected to bend or bow the pipelines.

Pipeline Area Classes

Minimum standards for pipeline safety are more stringent where there is a potential for greater impacts on human health and safety. Pipeline area classes are defined in 49 CFR Part 192.5 and are based on an estimate of the population density in the vicinity of the pipeline (see Table 4.2-15). Class location units are onshore areas that extend 655 feet (200 m) on either side of the centerline of any continuous 1-mile (1.6 km) length of pipeline.

Table 4.2-15 Pipeline Location Class Definitions

Class 1	An offshore area or any class location unit with 10 or fewer buildings intended for human occupancy.
Class 2	Any class location unit with more than 10 but fewer than 46 buildings intended for human occupancy.
Class 3	Any class location unit with 46 or more buildings intended for human occupancy or an area where the pipeline lies within 300 feet (91 meters) of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period. (The days and weeks need not be consecutive.)
Class 4	Any class location unit where buildings with four or more stories aboveground are prevalent.

Class locations for more populated areas require higher safety factors in pipeline design, testing, and operation. Pipeline area class locations are used to specify the maximum spacing allowed between sectionalizing block valves, which are used to isolate portions of the line to allow maintenance and are essential to limiting the amount of gas that can be released in the event of a leak or rupture along the pipeline. Regulations contained in 49 CFR Part 192.179 require every point on a natural gas transmission pipeline to be within a minimum of 10 miles (16 km) of a sectionalizing block location in Class 1 locations, within 7.5 miles (12 km) in Class 2 locations, within 4 miles (6.4 km) in Class 3 locations, and within 2.5 miles (4 km) in Class 4 locations. For onshore segments, the valve and operating device must also be readily accessible and protected from tampering and damage. Pipe wall thickness and pipeline design pressures, hydrostatic test pressures, maximum allowable operating pressure (MAOP), inspection and testing of welds, and frequency of pipeline patrols and leak surveys must all conform to higher standards in more populated areas.

OPS Advisory Bulletins

The following OPS Advisory Bulletins are listed for their significance to the proposed Project:

Accelerated Corrosion on New Pipelines

On November 12, 2003, the OPS issued an advisory notice entitled "Pipeline Safety: Corrosion Threat to Newly Constructed Gas Transmission and Hazardous Liquid Pipelines" (68 FR 64189). This action was prompted by the discovery of substantial external corrosion of a newly constructed gas transmission pipeline, apparently due to exposure to stray electrical currents from other underground utilities. Corrosion due to stray current is most often found on pipelines that cross other underground structures (such as other pipelines) or that follow overhead electric transmission lines. The OPS advisory recommends that each operator of a natural gas transmission pipeline determine whether new steel pipelines are susceptible to stray electrical currents and to carefully monitor and take action to mitigate detrimental effects.

Emergency Preplanning with Other Utilities

On May 23, 2005, the OPS issued Advisory Bulletin ADB–05–03, "Preplanning with owners of electric and other utilities for coordinated response to pipeline emergencies" (70 FR 29557) to remind operators of natural gas and hazardous liquid pipelines located near electric and other utilities of the need to preplan emergency response to ensure better coordination of response, and reduced damages, when a pipeline emergency occurs. The advisory notice emphasized that in planning emergency response, an operator should carefully look at the environment surrounding the pipeline facility and the risks that the environment will pose in the event of a pipeline emergency. Preplanning will help the operator identify issues that may arise in responding to pipeline emergencies and plan effective response before there is an emergency.

Pipeline Incident Reporting Requirements

In 2004, reporting requirements for natural gas transmission pipelines were increased in scope and frequency as a part of implementation of pipeline integrity management programs required under 49 CFR Part 192, Subpart O, which states that natural gas transmission lines located near sensitive sites, e.g., schools, nursing homes, and hospitals, or in more densely populated areas require implementation of additional safety measures than pipelines in more rural areas.

Table 4.2-16 summarizes incident reporting requirements for utility-owned and operated natural gas transmission pipelines in California implemented by the Pipeline Safety Improvement Act of 2003 (H.R. 6 Title VII, Subtitle C: Pipeline Safety – Parts I and II), which requires operators of natural gas transmission pipelines to follow more stringent

Table 4.2-16 Transmission Pipeline Incident and Safety-Related Condition Reporting Criteria in California

Reporting Period	Reporting Criteria
Pre-1984	Report incidents that: • Caused a death or personal injury requiring hospitalization; • Required taking any segment of a transmission line out of service; • Resulted in gas ignition; • Caused estimated damage to the property of the operator, or others, of a total of $5,000 or more; • Required immediate repair on a transmission line; • Occurred while testing with gas or another medium; or • Was significant in the judgment of the operator, even though it did not meet the above criteria.
After June 1984 (currently applicable)	Report incidents that: • Resulted in a release of natural gas; and • Caused a death or personal injury requiring in-patient hospitalization; • Caused estimated property damage, including the cost of the gas lost, of more than $50,000; or • Was significant in the judgment of the operator even though it did not meet the above criteria. Report the following safety-related conditions that exist on a pipeline that is less than 655 feet (200 m) from any building intended for human occupancy or any outdoor place of assembly or that is within the right-of-way of an active railroad, paved road, street, or highway: • General corrosion that has reduced the wall thickness to less than that required for the maximum allowable operating pressure; • Localized corrosion pitting to a degree where leakage might result; • Unintended movement or abnormal loading by environmental causes such as an earthquake, landslide, or flood, that impairs the serviceability of a pipeline; • Any material defect or physical damage that impairs the serviceability of a pipeline that operates at a hoop stress of 20 percent or more of its specified minimum yield strength; or • Any safety-related condition that could lead to an imminent hazard and causes (either directly or indirectly by remedial action of the operator), for purposes other than abandonment, a 20 percent or more reduction in operating pressure or shutdown of operation of a pipeline.
After August 2004 (currently applicable)	Semiannually report Pipeline Integrity Management Program status and actions: • The number of pipeline miles inspected versus program requirements; • The number of immediate repairs completed as a result of the integrity management inspection program; • The number of scheduled repairs completed as a result of the integrity management program; and • The number of leaks, failures, and incidents experienced, classified by cause.

reporting requirements imposed by the CPUC. Data provided pursuant to these new reporting requirements are not reflected in the pipeline incident data discussed in this section because the change in reporting requirements is more recent than the data.

Pipeline Safety Inspection and Enforcement

Onshore and offshore pipelines for the proposed Project would be subject to design review, construction and operational safety inspections, and enforcement by the Federal and State agencies identified in Table 4.2-3 above. Primary agencies have either statutory authority or authority through delegation of Federal powers to a State agency through a memorandum of agreement or regulatory mandate. For example, the U.S. Department of Transportation (USDOT), through the PHMSA OPS, has statutory authority over pipeline safety in the U.S. but has delegated that authority for intrastate utility-owned natural gas pipelines to the CPUC.

Pipelines to be operated or constructed by SoCalGas would be under the jurisdiction of the CPUC. The CPUC conducts its pipeline safety inspection and investigation activities through its Consumer Protection and Safety Division's Safety and Reliability Branch (SRB). CPUC staff engineers conduct annual compliance audits and inspections of SoCalGas' facilities in each of their operating areas, including field testing of specific pipeline facilities. In addition, the CPUC SRB staff may inspect and monitor any construction, operation, or maintenance activity on SoCalGas' transmission or distribution system for compliance with pipeline safety regulations. The CPUC would exercise its safety jurisdiction in the event that the proposed Project is approved and built and has the authority to inspect and evaluate design and construction of pipelines interconnecting with Cabrillo Port. The CPUC would provide ongoing safety oversight subsequent to construction through its comprehensive pipeline safety inspections.

4.2.8.3 Significance Criteria

A public safety impact from offshore or onshore natural gas pipelines would be considered significant and require additional mitigation if Project would result in any of the following adverse effects:

- Cause a loss of life or serious injury to people other than those employed by the Project; or
- Cause significant damage (major and long term or permanent) to one or more of the environmental resources discussed in this document.[4]

4.2.8.4 Impact Analysis and Mitigation

The Applicant has stated that the LNG to be imported to the Project would meet California's pipeline quality specifications without further treatment at the FSRU. The analyses conducted to evaluate the potential impacts to public safety are based on the

[4] The significance criteria specific to each resource for evaluating the consequences of accidents are discussed in subsequent sections of this document.

presumption that the LNG and the resulting natural gas would be of pipeline quality with very high methane content.

Potential Pipeline Incidents

The major hazards associated with the construction and operation of natural gas pipelines are the potential release of natural gas, fires, and explosions. Fires occurring as a result of a release from a pipeline can also cause the release of potentially toxic products of incomplete combustion and can also lead to secondary fires of nearby vehicles or structures, or wildfires. Pipeline accidents result in fewer fatalities annually than accidents involving other forms of transportation. A single pipeline accident, however, has the potential to cause a significant local impact, including injuries and fatalities to members of the public, property damage, disruption of community activities and traffic patterns, and disruptions to the local energy supply.

Pipeline incidents could result from earth movement such as landslides or earthquakes. A major earthquake or landslide could cause a rupture in a natural gas transmission pipeline leading to a release of odorized natural gas. Natural gas transmission lines could also be damaged intentionally, although they would not necessarily be considered a high value target, i.e., one where a single event could cause widespread destruction or loss of life.

Potential damage or injury that might occur as a result of unplanned releases of natural gas from high-pressure transmission pipelines depends on: (1) how the pipeline fails, e.g., a leak versus a rupture, (2) the nature of the gas discharge, e.g., the angle of the jet and whether the jet is obstructed, (3) the time to ignition (immediate, delayed, or no ignition), and (4) whether secondary fires in nearby structures, vehicles, or wild lands are ignited as a result of a fire at the pipeline.

Project pipelines would carry natural gas. Many contaminants and compounds present in native natural gas freeze and are removed during the process of liquefaction to form LNG. Major explosions in transmission pipelines occur infrequently, but have the potential to cause serious injuries or fatalities and property damage. The distance to thermal radiation levels that could cause serious injury to people for jet or trench fires depends on the pipeline diameter and operating pressure (GRI 2000):

High-pressure natural gas transmission and lower-pressure distribution pipelines are presently routed through or near residential areas in Oxnard and Santa Clarita. As shown in Section 2.4, “Onshore Pipelines and Facilities,” proposed onshore pipeline routes would largely avoid areas with higher population densities. In response to public comments on the October 2004 Draft EIS/EIR, onshore pipeline routes for the proposed Project were moved farther away from existing residential areas.

Estimated Risks of Project Pipeline Incidents

The potential unmitigated risks associated with the proposed Project pipelines were estimated from historical pipeline incident data. As shown in Table 4.2-17, there is a moderate chance that the Project pipelines would experience a reportable incident in any year; however, there is a very small chance that this incident would result in injuries, and an even smaller chance that a fatality would occur based on a review of the information on the table that demonstrate that fatalities are even more rare than other types of injuries.

Table 4.2-17 Estimated Annual Incident Frequencies/Risks: Gas Transmission Pipelines

Event or Outcome	Average Total Number per Year, U.S. Pipelines	Estimated Frequency (per pipeline mile)[a]
Reportable incident	87.5	2.7×10^{-4}
Injury requiring in-patient hospitalization	12.9	3.7×10^{-5}
Fatality	3.3	1×10^{-5}

Notes:

The worst case frequency estimates in this table are extremely conservative and are based on a nationwide mix of old and new transmission and gathering lines. The unmitigated frequencies for newly installed transmission lines (such as those proposed for this Project) would be expected to be much lower.

[a]Based on operation of a total of 324,600 miles (522,280 km) of gas transmission pipelines throughout the U.S. each year.

Impacts and Mitigation Measures

Where potential impacts may be significant, mitigation measures have been proposed to reduce potential risks associated with construction and/or operation of the pipelines in the proposed Project. Mitigation measures, as modified and approved by the responsible agencies, would be incorporated as conditions of any license or lease granted to the Applicant. A discussion of the differences between Applicant-proposed measures (AM) and agency-recommended mitigation measures (MM) is provided in Section 4.1.5, "Applicant Measures and Mitigation Measures."

Impact PS-3. Potential Release of Odorized Natural Gas due to Damage to Subsea Pipelines.

Fishing gear could become hung up on the pipelines and potentially damage one or both of the subsea pipelines. Similar damage may occur due to a seismic event or subsea landslide (Class I).

As described in Chapter 2, "Description of the Proposed Action," the twin 24-inch (0.6 m) diameter subsea pipelines carrying odorized natural gas would be buried using HDB from the onshore connection seaward approximately 0.6 miles (1 km) to water depths of 42.6 feet (13 m). In deeper waters, the offshore pipelines would be laid on the sea floor. Subsea pipeline segments laid directly on the sea floor would be concrete coated to provide additional stability in the areas where depths are still relatively shallow. The potential for commercial fishing activities such as trawling in the area near the pipelines is discussed in Section 4.16, "Socioeconomics."

Previous incidents of subsea natural gas pipeline ruptures due to third-party damage (dragging an anchor) have been concentrated in the Gulf of Mexico, where many older pipelines are not buried or concrete-coated, and where water depths are shallow for a considerable distance from shore. In several of those cases, in shallow waters (less than 10 to 20 feet [3 to 6 m]), the released natural gas formed a flammable cloud once it breached the ocean surface. In the case of the proposed Project, it is likely that mariners in the area would notice bubbling or frothing at the ocean surface, and the smell of the odorized gas would be detectable by people, marine life, or birds in the area.

Offshore pipelines that are installed where mean low tide water depths are less than 12 feet (3.7 m) are required to have a minimum cover of 36 inches (0.9 m) in soil or 18 inches (0.5 m) in consolidated rock; the pipelines would exceed this requirement at the shore crossing where they would be installed deep beneath the beach. Where mean low tide water depths are between 12 feet (3.7 m) and 200 feet (61 m), current regulations require only that the top of the pipe be below the natural bottom unless the pipe is supported by stanchions held in place by anchors or heavy concrete coating, or protected by some other equivalent means. PHMSA OPS has promulgated more stringent cover requirements for offshore pipelines installed in shallow water in the Gulf of Mexico but has not expanded these requirements to offshore California, in part because the State's more stringent seismic design criteria already require a more robust pipeline than is typically seen in Gulf waters.

The Applicant has proposed the following measures to reduce the potential for incidents due to piping or valve failures caused by third-party damage, material defects or operational fatigue, or natural phenomena:

AM PS-3a. **More Stringent Pipeline Design.** The Applicant would design and install pipelines to meet seismic criteria to ensure that pipeline integrity is maintained during severe seismic events that might be expected to bend or bow the pipelines.

AM PS-3a would ensure that pipeline integrity would be maintained during severe seismic events.

<u>Mitigation Measures for Impact PS-3: Release of Odorized Natural Gas from Damaged Subsea Pipelines.</u>

MM PS-3b. **Emergency Communication/Warnings.** The Applicant shall institute emergency plans and procedures that require immediate notification of vessels in any offshore area, including hailing and Securite broadcasts, and immediate notification of local police and fire services whenever the monitoring system indicates that there might be a problem with subsea pipeline integrity.

MM PS-3c. **Areas Subject to Accelerated Corrosion, Cathodic Protection System.** The Applicant shall identify any offshore or onshore areas where the new transmission pipelines may be subject to accelerated corrosion due to stray electrical currents, and implement precautions and mitigation measures as recommended in a November 12, 2003 Federal OPS pipeline safety advisory (68

FR 64189). Cathodic protection systems shall be installed and made fully operational as soon as possible during pipeline construction.

MM MT-1d. **Securite Broadcasts** (see Section 4.3, "Marine Traffic").

MM MT-3g. **Information for Navigational Charts** (see Section 4.3, "Marine Traffic").

MM PS-3b would reduce the likelihood of potential impacts to vessels in the area of the offshore pipelines and could increase the timeliness and/or effectives of emergency response systems other than those in place at the FSRU. MM PS-3c would increase the overall integrity of the offshore pipelines, thereby reducing the potential for accidents. MM MT-1d would decrease marine traffic congestion, thereby reducing the risk of vessel collision. MM MT-3g would ensure that the proposed changes to the navigational charts would be done promptly so that navigators would be notified of such changes. Once published, the safety zone and ATBA delineations on navigational charts would assist all mariners transiting the Project area to plan accordingly to avoid the safety zone.

The frequencies of significant events per pipeline mile have been very conservatively estimated for offshore pipelines at four in one hundred thousand that a pipeline incident would result in a serious public injury, and about one in one hundred thousand that a pipeline incident would result in a public fatality. These frequencies would be expected to be reduced for the proposed Project pipelines—and in some cases significantly decreased—with the implementation of the measures described above. Should such an incident occur, however, the impacts would still be significant, i.e., could cause serious injury or fatality to members of the public. Therefore, this impact would remain significant after mitigation.

Impact PS-4. Potential Release of Odorized Natural Gas due to Accidental Damage to Onshore Pipelines

The potential exists for accidental or intentional damage to the onshore pipelines or valves carrying odorized natural gas. Damage, fires, and explosions may occur due to human error, equipment failure, natural phenomena (earthquake, landslide, etc.). This would result in the release of an odorized natural gas cloud at concentrations that are likely to be in the flammable range (Class I).

As part of its application for the Project, the Applicant or its designated representative would be expected to certify that the pipelines and aboveground facilities associated with the Project would be designed, constructed, operated, and maintained in accordance with or to exceed the USDOT minimum Federal safety standards contained in 49 CFR Part 192. These regulations, which are intended to protect the public and prevent natural gas facility accidents and failures, include specifications for material selection and qualification; minimum design requirements; and protection of the pipeline from internal, external, and atmospheric corrosion. The USDOT regulations also incorporate, by reference, the additional codes and standards that are listed in the Design and Safety Standards Applicable to Natural Gas Transmission Pipelines Table included in Appendix C3. The Project would be subject to the versions of codes and standards in effect at the time that the design is initiated. Project pipelines would be built to Class 3 pipeline location standards.

Project-Specific Pipeline Valve Spacing and Design

Pipeline design criteria contained in 49 CFR Part 192 provide the minimum requirements for protecting public health and safety near natural gas pipelines. During the review of potential public safety impacts in the event of a release and ignition of natural gas from the transmission pipelines, concerns were noted that the assumptions underlying the Federal regulations for defining a potential impact radius (PIR) were not necessarily protective of safety for the manufactured/mobile home residential areas near Milepost (MP) 4.1 on the proposed Center Road Pipeline route. To address public safety concerns for the communities in this area, the CSLC and CPUC determined that it was appropriate for this project-specific case to require remote or automatic valve closure and to limit potential release duration and the quantity of natural gas that might be released from a ruptured pipeline segment by reducing the distance between the mainline valves (also called sectionalizing valves). Table 4.2-18 summarizes the minimum regulatory requirements as well as the proposed project-specific measures for this Project. Although the number of valves has been specified, the actual spacing between each of the valves and blowdown stacks would be determined during detailed engineering design. SoCalGas has committed to try to space the mainline valves at approximately equal distances.

The PIR depends on the diameter of the pipeline and the MAOP for that pipeline. The MAOP for the 36-inch (0.9 m) Center Road Pipeline and its alternatives is 1,100 psi, and the MAOP for the 30-inch (0.76 m) Line 225 Pipeline Loop in Santa Clarita and its alternative route is 845 psi.

The PIR for a release/fire at the metering station is estimated at 820 feet (250 m), which would not directly impact any residences in the immediate vicinity of the Ormond Beach Metering Station, and would have no impact on residences in Port Hueneme.

Pipeline safety regulations use the concept of High Consequence Areas (HCAs) to identify specific locales and areas where a release could have the most significant adverse consequences. See Appendix C3 for an explanation of the determination of HCAs. Preliminary identification of HCAs along the proposed Project pipeline and alternate routes is summarized in Table 4.2-19. The Applicant identified the HCAs in the table using the PIR established by the USDOT for various types of pipelines and gas pressures.[5]

[5] The significance criteria used for the USDOT regulatory definition of the PIR from a pipeline rupture and fire is the level that would cause human fatalities, estimated at 5,000 Btu/hr-ft^2 (15.8 kW/m^2) for a 40-second exposure. The significance criteria for this analysis is a level likely to cause serious injury to

Table 4.2-18 Design Guidelines and Project-Specific Valve Spacings

	49 CFR 192	Center Road Pipeline	Line 225 Loop Pipeline
Proposed pipeline description	----	~15.2 miles (24.5 km), 36-inch (0.9 m) diameter pipeline; MAOP = 1,100 psig.	~7 miles (11.3 km) long, 30-inch (0.76 m) diameter pipeline; MAOP = 845 psig.
Number of valves	Not specified. Requirement is for maximum distance between valves.	5 valves: station valves at Ormond Beach and Center Road, plus 3 mainline valves.	3 valves: station valves at Quigley and Honor Rancho, plus 1 mainline valve.
Line segment length (distance between sectionalizing block valves)	Class 1: 20 miles (32 km) Class 2: 15 miles (24 km) Class 3: 8 miles (12.9 km) Class 4: 5 miles (8 km)	Current classes along route: Class 1 and 3 AM: "Build to Class 3" Approx. distance between valves = 3.8 miles (6 km)	Current Classes along route: Class 1 and 3 AM: "Build to Class 3" Approx. distance between valves = 3.5 miles (5.6 km)
Blowdown assemblies	Not specified	Two 12-inch (0.3 m) blowdown stacks	Two 12-inch (0.3 m) blowdown stacks
Blowdown time (time for all gas to vent from ruptured segment)	Not specified	Venting through: Blowdown stacks: 15 min 33% Damage: 6 min Full rupture: 5 min	Venting through: Blowdown stacks: 9 min 33% Damage: 7 min Full rupture: 7 min
Station and mainline valve description	Not specified	Ball valve/actuator packages. Ball valves are full port, trunnion mounted, and include a mechanical position indicator, manual hydraulic override system, and pressure regulated supply equipment (for valve actuators).	
Station and mainline valve actuator	Not specified	Actuators are pneumatic powered double acting scotch yoke with adjustable travel stops. Natural gas is the power media for operating the actuator.	
Station valve remote control[a]	Not specified	Communications/RTU control panel and UPS system, plus external power and telephone service.	
Mainline valve automatic line break controls[a]	Not specified	Pressure sensor/RTU controller package with a solar panel and battery. No external power is needed.	

Notes:

ID = internal diameter; MAOP = maximum allowable operating pressure; psig = pounds per square inch gauge; RTU = remote telecommunication unit; UPS = universal power supply.

[a]SoCalGas does not combine automatic line break controls with remote controls on a single valve.

humans for a similarly short exposure, which is why the thermal criteria for incidents involving LNG releases from the FSRU or LNG tankers is set at 1,600 Btu/hr-ft^2 (5 kW/m^2).

Table 4.2-19 Preliminary Identification of High Consequence Areas (HCAs) on Project Pipeline Routes

Milepost Range	Pipeline Class per 49 CFR Part 192.905	HCA Milepost Range	HCA Method	Criteria Triggering HCA[a]
Proposed Project				
Center Road Pipeline: Potential Impact Radius = 818 feet (250 m)				
Low tide mark to 7.6	Class 1	Low tide mark to 0.0 0.0 to 0.15	1	Site: shore crossing, outdoor area within <750 feet (230 m) of pipeline
		~4.1	1	Sites: mobile home park, outdoor area Density: less robust housing and ≥ 20 buildings intended for human occupancy (BIHO)
7.6 to 8.6	Class 3	--		
8.6 to 9.2	Class 1	--		
9.2 to 9.6	Class 3	--		
9.6 to 14.7	Class 1	13.45 to 13.75	1	Site: Saticoy Country Club Clubhouse
Line 225 Loop Pipeline: Potential Impact Radius = 605 ft (184 m)				
0.0 to 0.6	Class 1	--		
0.6 to 7.1	Class 3	1.59 to 2.45	1	Density ≥ 20 BIHO
		3.53 to 3.93	1	Density ≥ 20 BIHO
		5.0 to 5.54	1	Density ≥ 20 BIHO
7.1 to 7.71	Class 1	--		
Alternative Deepwater Port				
Santa Barbara Channel/ Mandalay Shore Crossing/ Gonzales Road Pipeline Alternative[a]				
Low tide mark to ~3.0	Class 1	Low tide mark to 0.0 0.0 to 0.15	1	Site: shore crossing, outdoor areas within <750 feet (230 m) of pipeline (McGrath State Beach).
~3.0 to ~6.5	Class 3	~3.0 to ~6.5 3.0 3.8 4.2 5.6 6.06.6	1	Density ≥ 20 BIHO site(s), including several schools
~6.5 to 6.7 (junction w/Center Road Pipeline Alt 1 at MP 8.0)	Class 1	--		

Table 4.2-19 Preliminary Identification of High Consequence Areas (HCAs) on Project Pipeline Routes

Milepost Range	Pipeline Class per 49 CFR Part 192.905	HCA Milepost Range	HCA Method	Criteria Triggering HCA[a]
Alternative Shore Crossings				
Arnold Road Shore Crossing/ Arnold Road Pipeline Alternative				
Low tide mark to 1.5 (junction with Center Road Pipeline at MP 1.8)	Class 1	Low tide mark to 0.0 0.0 to 0.15	1	Site: shore crossing, outdoor area within <750 feet (230 m) of pipeline
Point Mugu Shore Crossing/Casper Road Pipeline Alternative				
Low tide mark to 1.5 (junction with Center Road Pipeline at MP 2.5)	Class 1	Low tide mark to 0.0	1	Site: shore crossing, outdoor area within <750 feet (230 m) of pipeline
Alternative Onshore Pipeline Routes				
Center Road Pipeline Alternative 1 Potential Impact Radius = 820 feet (250 m)				
0.0 to 1.4	Class 1	1.3 to 1.4	1	Density ≥ 20 BIHO
1.4 to 3.3	Class 3	1.4 to 3.3 1.75 to 2.35 2.65 to 3.15	1	Density ≥ 20 BIHO Site(s) Site(s) Site(s)
3.3 to 5.3	Class 1	4.0 4.1	1	Site(s) Site(s)
5.3 to 9.5	Class 3	6.95 to 7.25 7.65 to 9.15 8.1 to 9.5	1	Site(s) Site(s) Density ≥ 20 BIHO Site(s)
9.5 to 10.0	Class 1	--		
10.0 to 11.3	Class 2	10.25 to 10.55	1	Site(s)
11.3 to 15.0	Class 1	14.15 to 14.45	1	Site(s)
Center Road Pipeline Alternative 2				
0.0 to 1.4	Class	1.3 to 1.4	1	Density ≥ 20 BIHO
1.4 to 3.3	Class 3	1.4 to 3.7 1.75 to 2.35 2.65 to 3.15	1	Density ≥ 20 BIHO Site(s) Site(s)
3.3 to 3.6	Class 2	--		

Table 4.2-19 Preliminary Identification of High Consequence Areas (HCAs) on Project Pipeline Routes

Milepost Range	Pipeline Class per 49 CFR Part 192.905	HCA Milepost Range	HCA Method	Criteria Triggering HCA[a]
3.6 to 12.6	Class 1	10.65 to 10.95	1	Site(s)
Center Road Pipeline Alternative 3				
0.0 to 9.6				Route is the same as for the Center Road Pipeline Proposed Route.
9.6 to 12.5				Route is the same as for the Center Road Pipeline proposed route.
12.5 to 14.3	Class 1	13.45 to 13.75	1	Site: Mesa Union School
Line 225 Pipeline Loop Alternative				
0.0 to .0.6	Class 1	--		
0.6 to 5.4	Class 3	1.59 to 2.45 3.53 to 3.93 4.8 to 5.35	1	Density ≥ 20 BIHO Density ≥ 20 BIHO Density ≥ 20 BIHO
5.4 to 5.7	Class 1	--		
5.7 to 6.6	Class 3	--		
6.6 to 7.22	Class 1	--		
Line 225 Pipeline Loop HDD River Crossing Alternative				
0.0 to 7.22				Route is the same as for the Line 255 Loop Pipeline proposed route

Notes:

BIHO = Building intended for human occupancy.

[a]Pipeline class and HCA housing density estimated from general, not detailed maps; information is illustrative and not conclusive. Identification of specific sites, e.g., MP locations of schools, hospitals, care facilities, is not included in this table due to security concerns.

The potential annual risk of a fatality associated with the proposed new pipelines would be expected to be less (and potentially considerably less) than the numbers presented in Table 4.2-17 above because of the current requirements for increased safety margins in design, greater inspection detail and frequencies, and the implementation of the new pipeline integrity management program requirements for HCAs identified along these pipelines.

The Applicant has proposed the following measures to reduce the potential of incidents due to failures caused by third-party damage, material defects or operational fatigue, or natural phenomena.

AM PS-4a. Class 3 Pipeline Design Criteria. The Applicant or its designated representative would construct all pipeline segments to meet the minimum design criteria for a USDOT Class 3 location, which would improve safety and reduce the need to reconstruct the pipeline segments as additional development and population densities increase along the pipeline corridor.

AM PS-4a would improve pipeline integrity and safety and thereby reduce the likelihood of potential pipeline accidents.

Mitigation Measures for Impact PS-4: Release of Odorized Natural Gas from Damaged Pipelines.

MM PS-4b. **Pipeline Integrity Management Program.** The Applicant shall develop and implement a pipeline integrity management program, including confirming all potential HCAs (including identification of potential sites from "licensed" facility information [day care, nursing care, or similar facilities] available at the city and county level) and ensuring that the public education program is fully implemented before beginning pipeline operations.

MM PS-4c. **Install Additional Mainline Valves Equipped with Either Remote Valve Controls or Automatic Line Break Controls.** The Applicant shall install five approximately equally spaced sectionalizing valves with appropriately sited and sized blowdown stacks on the Center Road Pipeline. The Applicant shall install three approximately equally spaced sectionalizing valves with appropriately sited and sized blowdown stacks on the Line 225 Pipeline Loop. The number of valves includes the station valves at each end of these pipelines. All valves shall be equipped with either remote valve controls or automatic line break controls.

MM PS-4d. **Treat Shore Crossing as Pipeline HCA.** The Applicant shall treat any onshore public beach area, under which is located a pipeline(s) that is carrying natural gas, as an HCA.

MM PS-4e. **Automatic Monitoring for Flammable Gas.** The Applicant shall design and install an automatic monitoring system (sniffer) in shore crossing HCAs.

MM PS-4f. **Emergency Communication and Warnings.** The Applicant shall institute emergency plans and procedures that require immediate notification of vessels in any nearshore area, immediate notification of local police and fire services, and visual and audible alarms to alert members of the public in the area, e.g., warning horns and strobe lights located along the onshore pipeline HCA corridor whenever the monitoring system indicates that there might be a problem with the pipeline integrity in that area. The emergency plans shall be in compliance with OPS Advisory Bulletin ADB-05-

03, which requires preplanning with other utilities for coordinated response to pipeline emergencies.

MM PS-3c. Areas Subject to Accelerated Corrosion, Cathodic Protection System.

MM PS-4b would increase public awareness and ensure that up-to-date information regarding sensitive land uses is maintained during the Project. MM PS-4c would limit the affected area from a potential pipeline accident by allowing SoCalGas to automatically control the influx of gas into sections of the pipeline system. MM PS-4d would improve the integrity of the pipeline at beach recreation areas where people could be located in the vicinity of the pipelines. MM PS-4e would improve the safety of the system by automatically monitoring for gas leaks. MM PS-4f would improve the timeliness and effectiveness of emergency response measures in the unlikely event of a potential pipeline accident. Finally, MM PS-3c would increase the overall integrity of the pipelines, thereby reducing the potential for accidents.

The annual frequencies of significant events per pipeline mile have been very conservatively estimated for onshore pipelines at about four in one hundred thousand that a pipeline incident would result in a serious public injury and about one in one hundred thousand that a pipeline incident would result in a public fatality. These frequencies would be expected to be reduced for the proposed Project pipelines—and in some cases significantly decreased—with the implementation of the measures described above. Should such an incident occur, however, the impacts would still be significant, i.e., could cause serious injury or fatality to members of the public. Therefore, this impact would remain significant after mitigation.

Impact PS-5. Increased Potential for Injury, Fatality, and Property Damage Due to Fire or Explosion in Areas with Less Robust Housing Construction and Outdoor Activity.

In the event of an accident, there is a greater likelihood of injury, fatality, and property damage near Center Road Pipeline MP 4.1, an HCA (Class I).

HCAs are determined by the pipeline operator in consultation with others using the definitions and guidance provided in 49 CFR Part 192. The equation for calculating a PIR is based on the following assumptions (GRI 2000):

- People who are outside near the pipe rupture will be able to reach adequate shelter within 200 feet (61 m) of their location, with travel time presumed to be no more than 30 seconds. This assumes that a person takes between 1 and 5 seconds to evaluate the situation and then runs at 5 mph (2.5 m/s) to reach shelter; and
- Protection of individuals inside a structure and ignition of nearby structures is based on a typical wooden structure, using thermal properties specifically for American whitewood. These wooden structures are presumed to provide adequate protection indefinitely for people who have taken shelter inside them.

It is unlikely that the structure of many older mobile homes (manufactured housing built before 1976 when more stringent construction standards were imposed by the Housing and Urban Development code) or travel trailers being used for temporary or semi-permanent housing in the Project area would provide this level of protection. Ignition of mobile homes and travel trailers will likely occur at lower radiant heat levels than the typical construction used to develop the PIR equation. Even without ignition, mobile home construction may not be sturdy enough to withstand the potential blast forces when a natural gas release is ignited. In addition, inhabitants of mobile homes often include older or elderly residents and families with small children who would be difficult to evacuate and are very unlikely to be able to run for shelter at 5 mph (2.5 m/s).

The Applicant determined that mobile home parks on Pidduck and Dufau Roads near MP 4.1 of the proposed Center Road pipeline route did not trigger HCA requirements in the environmental assessment evaluation, based on the presence of only ten buildings intended for human occupancy within the potential impact circle (PIR of 818 feet [250 m]). However, a field inspection by E & E staff in August 2004 indicated that the small housing community located on Dufau Road includes community gardens. The arrangement of outdoor furniture and the level of human activity outdoors indicate that there is likely significant community activity outside of the residences.

Based on the average household size in Census Tract 47.02 (U.S. Census Bureau 2000) of about four people, this cluster of ten buildings could reasonably be expected to include more than 20 people in an outside area on at least 50 days in any 12-month period, which meets the definition of an identified site for the purposes of defining an HCA.

The Applicant has incorporated the following measure to reduce the potential of incidents to the mobile home parks on Pidduck and Dufau Roads near MP 4.1 of the Center Road pipeline route:

AM PS-4a. Class 3 Pipeline Design Criteria.

AM PS-4a would improve pipeline integrity and safety and thereby reduce the likelihood of potential pipeline accidents.

<u>Mitigation Measure for Impact PS-5: Increased Potential for Injury, Fatality, and Property Damage Due to Fire or Explosion in Areas with Less Robust Housing Construction and Outdoor Activity.</u>

MM PS-5a. Treat Manufactured Home Residential Community as a High Consequence Area. The Applicant shall treat as a HCA those areas where the potential impact radius includes part or all of a manufactured-home residential community, including outdoor gardens and areas with one or more normally occupied mobile homes or travel trailers used as temporary or semi-permanent housing, and outdoor gardens. The Applicant shall enact for these areas the pipeline safety requirements contained in 49 CFR Part 192 Subpart O.

MM PS-5a would extend additional pipeline safety measures for areas along the pipeline route with a predominance of semi-permanent housing.

Potential impacts from a natural gas release in areas with less robust housing construction and outdoor activities would be reduced with the implementation of the measures described above; however, the impacts would still be potentially significant should an incident occur. Therefore this impact would remain significant after mitigation.

A summary of impacts and mitigation measures for Project pipelines is provided in Table 4.2-20.

Table 4.2-20 Summary of Public Safety Impacts and Mitigation Measures for Project Pipelines

Impact	Mitigation Measure(s)
Impact PS-3. Fishing gear could become hung up on the pipelines and potentially damage one or both of the subsea pipelines. Similar damage may occur due to a seismic event or subsea landslide (Class I).	**AM PS-3a. More Stringent Pipeline Design.** The Applicant would design and install pipelines to meet seismic criteria to ensure that pipeline integrity is maintained during severe seismic events that might be expected to bend or bow the pipelines. **MM PS-3b. Emergency Communication/ Warnings.** The Applicant shall institute emergency plans and procedures that require immediate notification of vessels in any offshore area, including hailing and Securite broadcasts, and immediate notification of local police and fire services whenever the monitoring system indicates that there might be a problem with subsea pipeline integrity. **MM PS-3c. Areas Subject to Accelerated Corrosion, Cathodic Protection System.** The Applicant shall identify any offshore or onshore areas where the new transmission pipelines may be subject to accelerated corrosion due to stray electrical currents, and implement precautions and mitigation measures as recommended in a November 12, 2003, Federal OPS pipeline safety advisory (68 FR 64189). Cathodic protection systems shall be installed and made fully operational as soon as possible during pipeline construction. **MM MT-1d. Securite Broadcasts** (see Section 4.3, "Marine Traffic"). **MM MT-3g. Information for Navigational Charts** (see Section 4.3, "Marine Traffic").
Impact PS-4. The potential exists for accidental or intentional damage to the onshore pipelines or valves carrying odorized natural gas. Damage may occur due to human error, equipment failure,	**AM PS-4a. Class 3 Pipeline Design Criteria.** The Applicant or its designated representative would construct all pipeline segments to meet the minimum design criteria for a USDOT Class 3

Table 4.2-20 Summary of Public Safety Impacts and Mitigation Measures for Project Pipelines

Impact	Mitigation Measure(s)
natural phenomena (earthquake, landslide, etc.). This would result in the release of an odorized natural gas cloud at concentrations that are likely to be in the flammable range (Class I).	location, which would improve safety and reduce the need to reconstruct the pipeline segments as additional development and population densities increase along the pipeline corridor. **MM PS-4b. Pipeline Integrity Management Program.** The Applicant shall develop and implement a pipeline integrity management program, including confirming all potential High Consequence Areas (including identification of potential sites from "licensed" facility information [day care, nursing care, or similar facilities] available at the city and county level) and ensuring that the public education program is fully implemented before beginning pipeline operations. **MM PS-4c. Install Additional Mainline Valves Equipped with Either Remote Valve Controls or Automatic Line Break Controls.** The Applicant shall install five approximately equally spaced sectionalizing valves with appropriately sited and sized blowdown stacks on the Center Road Pipeline. The Applicant shall install three approximately equally spaced sectionalizing valves with appropriately sited and sized blowdown stacks on the Line 225 Pipeline Loop. The number of valves includes the station valves at each end of these pipelines. All valves shall be equipped with either remote valve controls or automatic line break controls. **MM PS-4d. Treat Shore Crossing as Pipeline HCA.** The Applicant shall treat any onshore public beach area, under which is located a pipeline(s) that is carrying natural gas, as an HCA. **MM PS-4e. Automatic Monitoring for Flammable Gas.** The Applicant shall design and install an automatic monitoring system (sniffer) in shore crossing HCAs. **MM PS-4f. Emergency Communication and Warnings.** The Applicant shall institute emergency plans and procedures that require immediate notification of vessels in any nearshore area, immediate notification of local police and fire services, and visual and audible alarms to alert members of the public in the area, e.g., warning horns and strobe lights located along the onshore pipeline HCA corridor whenever the monitoring system indicates that there might be a problem with the pipeline integrity in that area. The emergency plans shall be in compliance with OPS Advisory Bulletin ADB-05-03, which requires preplanning with other utilities for coordinated response to pipeline emergencies.

Table 4.2-20 Summary of Public Safety Impacts and Mitigation Measures for Project Pipelines

Impact	Mitigation Measure(s)
	MM PS-3c. Areas Subject to Accelerated Corrosion, Cathodic Protection System.
Impact PS-5. In the event of an accident, there is a greater likelihood of injury, fatality, and property damage near Center Road Pipeline MP 4.1, an HCA (Class I).	**AM PS-4a. Class 3 Pipeline Design Criteria**. **MM PS-5a. Treat Manufactured Home Residential Community as a High Consequence Area.** The Applicant shall treat as an HCA those areas where the potential impact radius includes part or all of a manufactured-home residential community, including outdoor gardens and areas with one or more normally occupied mobile homes or travel trailers used as temporary or semi-permanent housing, and outdoor gardens. The Applicant shall enact for these areas the pipeline safety requirements contained in 49 CFR Part 192 Subpart O.

4.2.9 Alternatives

4.2.9.1 No Action Alternative

As explained in greater detail in Section 3.4.1, “No Action Alternative,” under the No Action Alternative, MARAD would deny the license for the Cabrillo Port Project and/or the CSLC would deny the application for the proposed lease of State tide and submerged lands for a pipeline right-of-way. The No Action Alternative means that the Project would not go forward and the FSRU, associated subsea pipelines, and onshore pipelines and related facilities would not be installed. Accordingly, none of the potential environmental impacts identified for the construction and operation of the proposed Project would occur.

Since the proposed Project is privately funded, it is unknown whether the Applicant would fund another energy project in California; however, should the No Action Alternative be selected, the energy needs identified in Section 1.2, "Project Purpose, Need and Objectives," would likely be addressed through other means, such as through other LNG or natural gas-related pipeline projects. Such proposed projects may result in potential environmental impacts of the nature and magnitude of the proposed Project as well as impacts particular to their respective configurations and operations; however, such impacts cannot be predicted with any certainty at this time.

4.2.9.2 Alternative DWP Location – Santa Barbara Channel/Mandalay Shore Crossing/Gonzales Road Pipeline Alternative

The FSRU mooring point for this alternative would be approximately 7.7 NM (8.9 miles or 14.3 km) offshore of Pitas Point and approximately midway between the existing Grace and Habitat production platforms located on the Federal Outer Continental Shelf (OCS) in the Santa Barbara Channel. This alternative would be approximately 5.8 NM

(6.7 miles or 10.7 km) landward from the coastal shipping lanes and more than 4.6 NM (5.3 miles or 8.5 km) from the nearest offshore production platform.

This proposed alternate location is further from the coastal shipping lanes than the proposed Project mooring location; however, LNG carriers heading for this alternate mooring location would be required to cross both shipping lanes. This would increase the potential for a collision involving an LNG carrier and would be expected to increase the number of members of the general public that might be affected by impacts from a fire or explosion involving either a carrier or the FSRU. In addition, because there are more fishing and recreational vessels in the area of this alternate location, there would be an increased potential for collisions of these smaller vessels with the FSRU, LNG carriers, or tug/supply vessels serving the proposed Cabrillo Port. This could result in an increased number of injuries or fatalities to members of the general public and could result in greater short-term environmental impacts due to releases of oil or fuel from the smaller damaged vessels.

The IRA analyzed the potential frequency of collision between various marine vessels and the FSRU specific to the proposed Project mooring location. The increased distance from this alternate mooring location and the nearest shipping lane would be expected to result in a reduced potential for large vessel impacts with the FSRU and a reduced potential risk of a release due to a high speed impact with one of these larger vessels.

Computer modeling results for worst credible case LNG releases from the FSRU at its proposed location indicate that significant impacts to the public could extend 6.3 NM (7.3 miles or 11.7 km) from the alternate FSRU location. If the same modeling criteria were used for the alternate location, the worst credible vapor cloud fire event would come within about 1 NM (1.2 miles or 1.9 km) from shore. A site-specific risk evaluation would be needed to quantify the potential risks to members of the general public if this alternative were selected.

The pipeline route from the alternate mooring point to Platform Gilda would be in waters approximately 270 feet (82 m) deep. This route would continue in an existing subsea pipeline corridor from Platform Gilda to the Mandalay Generating Station. Like the proposed Project, the alternative pipeline route is proposed to be laid on the sea floor. At a point approximately 1 NM (1.2 miles or 1.9 km) offshore, in waters approximately 43 feet (13 m) deep, the pipeline it would be buried in an HDB bore from the shore crossing, similar to that described for the proposed Project. Although routing the subsea pipelines in an existing, well-known pipeline corridor may reduce the chance for third-party damage, e.g., from dragging an anchor or tangling in trawling gear, the potential impacts to public safety for the subsea pipelines would be similar to those described for the proposed Project.

Although the length of the HDB bore would be slightly longer, with a longer segment of pipe carrying odorized gas along the shoreline, the potential impacts to public safety from this alternative shore crossing, backup odorization facility, and connection to an existing SoCalGas natural gas pipeline at the Mandalay Generating Station would be similar to the proposed Project.

From the Mandalay Generating Station, the onshore pipeline would be installed primarily in existing pipeline rights-of-way along Harbor Boulevard, West Gonzales Road, East Gonzales Road, and Rose Road, where it would meet Center Road Pipeline Alternative 1 near MP 8.0. The presence of several schools located along this route could trigger HCA requirements.

4.2.9.3 Alternative Onshore Pipeline Routes

Center Road Pipeline Alternative 1

This alternative route passes through more densely populated areas than the proposed pipeline route; therefore, more people could potentially be affected by an accident. There are also greater numbers of potential HCAs identified along this alternate pipeline route compared with the proposed route.

Center Road Pipeline Alternative 2

The potential impacts to public safety for this route are the same as for the proposed Center Road Pipeline route except that the alternative route follows Pleasant Valley Road and Wolff Road rather than backtracking to the southwest on Pleasant Valley Road before running northward along Del Norte Boulevard, which travels through a slightly more rural area with less dense housing than the proposed route (resulting in potentially lower impacts to public safety).

Center Road Pipeline Alternative 3

The potential impacts to public safety for this route would be the same as for the proposed route from MP 0.0 to about MP 12.5, where the routes are identical. From about MP 12.5, however, the alternate route continues to the northwest along Santa Clara Avenue instead of turning to the northeast along State Route 118 (Los Angeles Avenue) and along Clubhouse Drive past the Saticoy Country Club Clubhouse. From this point, the alternate route travels through an area with a similar housing density as the proposed route, but would be located in relatively close proximity to Mesa Union School. There are potentially greater impacts to public safety from the alternative than the proposed route due to the difference in population and age group of the people most likely to be in the area near the pipeline (a large number of K-8 students versus a smaller number of people that would primarily be adults).

Line 225 Pipeline Loop Alternative

The potential impacts to public safety for this route are the same as for the proposed route from MP 0.0 to about MP 4.8 and from approximately MP 6.7 to MP 7.71, where the routes are identical. From about MP 4.8, however, the alternate route continues northwest along State Route 126 (Magic Mountain Parkway) rather than veering northward on McBean Parkway, which travels through an area with less dense housing than the proposed route (resulting in potentially lower impacts to public safety).

Line 225 Pipeline Loop HDD River Crossing Alternative

The potential impacts to public safety for this route are similar, but slightly less, compared to those for the proposed route. The routes are essentially identical, but river crossings in this alternate would be done using HDD rather than installing the pipeline on existing bridges. Under this alternative, the absence of aboveground high-pressure natural gas pipelines attached directly to the side or under bridges on major transportation routes results in a less attractive target for an intentional attack on the pipeline, and hence poses potentially lower impacts on public safety.

4.2.9.4 Alternative Shore Crossing/ Pipeline Route

Point Mugu Shore Crossing/Casper Road Pipeline

The potential impacts on public safety for this alternate shore crossing and 1.5-mile (2.4 km) long alternative pipeline route would be similar to those associated with MP 0.0 to approximately MP 2.5 of the proposed Center Road Pipeline, but would be slightly less because the alternative route is less traveled than the proposed route.

Arnold Road Shore Crossing/Arnold Road Pipeline

The potential impacts to public safety for this alternate shore crossing and 1.5-mile (2.4 km) long alternative pipeline route are similar to those associated with MP 0.0 to approximately MP 1.8 of the proposed Center Road Pipeline, which this alternative would replace.

4.2.10 References

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